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The report is a summary of major oil shale extraction and retorting development activities. The potential impacts on the physical environment which could result from commercial oil shale development are discussed relative to sources, properties, and quantities of wastes. The report describes existing air, water, and land resources in northwestern Colorado and northeastern Utah. The identification of potential impacts of oil shale development on these resources, pollution control technologies and management plans are reviewed. Potential hazards associated with refining and end use of shale oil products are evaluated. The major environmental monitoring and impact studies are identified, and the scope of oil shale development projects is assessed by this document.

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FOREWORD

When energy and material resources are extracted, processed, converted, and used, the related pollutional impacts on our environment and even on our health often require that new and increasingly more efficient pollution control methods be used. The Industrial Environmental Research Laboratory - Cincinnati (IERL-Ci) assists in developing and demonstrating new and improved methodologies that will meet these needs both efficiently and economically.

The material presented in this report summarizes the status of oil shale technologies and development activities, the nature and sources of pollution from oil shale development and their potential impacts on the physical environment. This information has been collected from related on-going industrial and government activities to provide a consolidated data source for planners and researchers concerned with oil shale development, to identify data and research gaps so that priorities for subsequent efforts in this area can be defined, and to establish the baseline material from which later environmental assessments can be made and related pollution control methods can be developed. Further information can be obtained from the Energy Systems Environmental Control Division, IERL-Cincinnati.

David G. Stephan
Director
Industrial Environmental Research Laboratory
Cincinnati

ABSTRACT

This Preliminary Environmental Assessment has been assembled from a wide variety of governmental and industrial data sources, including the Detailed Development Plans filed by federal lease tract developers as recently as June 1976. This document reviews potential environmental impacts that could result from direct or indirect discharge of air, water, and solid wastes, and some of the environmental control technology which has been developed or proposed. Secondary pollution effects, such as those stemming from population influx, are not considered. The primary purpose of this document is the identification of important environmental research areas in oil shale technology, and for setting research priorities.

Chapter 1 is an introduction and summary of the Preliminary Environmental Assessment (PEA). Chapter 2 presents a brief review of oil shale extraction and retorting technologies. The discussion includes the history, technology, development plans, and environmental programs of the major contenders for commercial development. Chapter 3 reviews the sources and nature of pollution from shale oil operations including the pollutant inventories presented by the various developers for air, liquid and solid waste emissions. Chapter 4 describes the baseline environmental conditions and discusses potential environmental impacts of the various technologies and developments. Chapter 5 is a brief review of shale oil upgrading and refining experiences to date, and of waste streams and hazards associated with refining and handling of shale oil. Chapter 6 is a summary of monitoring projects and studies which have been or are being conducted in the Piceance and Uinta Basins, and which are relevant to oil shale development.

This report was submitted in partial fulfillment of Contract 68-02-1881 by TRW Environmental Engineering Division under the sponsorship of the U.S. Environmental Protection Agency. This report covers the period of June 1, 1975 through June 1, 1976, and work is continuing toward the final project report "Assessment of the Environmental Impacts from Oil Shale Development" to be published in mid-1977.

CONTENTS

FOREWORD iii

ABSTRACT iv

FIGURES ix

TABLES x

SUMMARY OF METRIC/ENGLISH UNIT EQUIVALENTS xii

1.0 INTRODUCTION AND SUMMARY 1

2.0 THE STATUS OF OIL SHALE TECHNOLOGIES AND DEVELOPMENT ACTIVITIES. . 7
- 2.1 The Extraction and Preparation of Oil Shale for Retorting. . 7
  - 2.1.1 History 7
  - 2.1.2 Underground Room and Pillar Mining 10
  - 2.1.3 Open Pit Mining 14
  - 2.1.4 Mining for In-Situ Retorting 19
  - 2.1.5 Advanced Mining Methods 19
  - 2.1.6 Storage, Transport and Crushing of Oil Shale 22
- 2.2 Surface Retorting Technologies and Development Plans 24
  - 2.2.1 TOSCO II Retorting Process 24
  - 2.2.2 The Paraho Processes 27
  - 2.2.3 The Union Oil Process 33
  - 2.2.4 Superior Oil Process 36
  - 2.2.5 Lurgi-Ruhrgas Process 40
- 2.3 Commercial Development Plans Employing In-Situ Technology . 41
  - 2.3.1 The Occidental Modified In-Situ Process 41
  - 2.3.2 Western Oil Shale Corporation (WESTCO) 46
  - 2.3.3 Geokinetics, Inc. 46
  - 2.3.4 ERDA In-Situ Research, Development and Demonstration Project 46

2.4 Federal Oil Shale Lease Tracts 46
2.4.1 Tract C-a - Rio Blanco Oil Shale Project (RBOSP) . . . 48
2.4.2 Tract C-b - Roxana 52
2.4.3 Tracts U-a/U-b - White River Shale Project (WRSP) . . . 53
2.4.4 Federal In-Situ Lease Tract Nominations 55

3.0 THE NATURE AND SOURCES OF EMISSIONS, EFFLUENTS AND SOLID WASTES FROM SHALE OIL OPERATIONS 60
3.1 Atmospheric Emissions 60
3.1.1 A Comparison of Retorting Processes for Potential Emissions 62
3.1.2 Process Emissions Inventories 67
3.1.3 Fugitive Emissions Inventories 73
3.2 Water Requirements and Wastewater Processing 76
3.2.1 Water Requirement Estimates for Oil Shale Development 76
3.2.2 Sources and Nature of Wastewater 78
3.2.3 Specific Process Wastewaters 80
3.2.4 Process Wastewater Treatment 83
3.3 Solid Wastes Associated with Oil Shale Extraction and Processing 86
3.3.1 Raw Shale Fines 86
3.3.2 Retorted Shales 87
3.3.3 Other Shale Derived Solid Wastes 91
3.3.4 Non-Shale Solid Wastes 91
3.3.5 Inventory of Solid Wastes 93

4.0 POTENTIAL IMPACTS OF EXTRACTION AND PROCESSING ACTIVITIES ON THE PHYSICAL ENVIRONMENT 99
4.1 Air Quality Impacts of Oil Shale Extraction and Processing . 99
4.1.1 Baseline Characterization of Meteorology and Air Quality 99
4.1.2 Review of Model Application to Oil Shale Related Emissions in Colorado and Utah 103
4.1.3 Assessment of Models and Model Concepts Applied to Oil Shale Emissions 108
4.1.4 Comparison of Modeling Results 109

4.2 Impacts on Water Quality and Hydrology 113
  4.2.1 Existing Surface Water Quality and Flow 113
    4.2.1.1 Upper Colorado River Basin 113
    4.2.1.2 Piceance Creek Basin 113
    4.2.1.3 Uinta Basin 116
  4.2.2 Existing Ground Water Quality and Yields 117
    4.2.2.1 Piceance Creek Basin 117
    4.2.2.2 Uinta Basin 122
  4.2.3 Effects of Water Withdrawal by Oil Shale Development on the White and Colorado Rivers 122
  4.2.4 Effects of Development on Local Surface and Groundwater. 124
4.3 Potential Impacts Associated with Solid Waste Disposal . . . 131
  4.3.1 Solid Waste Disposal Plans for Oil Shale Development . 131
  4.3.2 Potential Hazards and Pollution Problems 140
  4.3.3 Experience in Establishing Vegetative Cover on Retort Shale Piles 141

5.0 THE REFINING AND END USE OF SHALE OIL PRODUCTS 148
  5.1 Upgrading and Refining of Shale Oil 148
    5.1.1 Upgrading Plans for Oil Shale Developments 148
    5.1.2 Experiences in Oil Shale Refining 148
  5.2 Waste Streams and Hazards Associated with Refining and Handling of Shale Oil 153
    5.2.1 Waste Streams 153
    5.2.2 Carcinogenic Properties of Crude Shale Oils and Refined Products 153
  5.3 Emissions from the Combustion of Shale Oil Products 157

6.0 ENVIRONMENTAL MONITORING PROGRAMS AND STUDIES 160
  6.1 Monitoring and Environmental Studies by Private Industry, Universities, and certain Government Agencies 160
  6.2 Environmental Programs of the Federal Prototype Oil Shale Leasing Program 160
    6.2.1 Geotechnical Data Gathering 167
    6.2.2 Environmental Baseline Programs 168
    6.2.3 Continuous Monitoring Programs 170

6.3 Comments on Monitoring Programs 170
  6.3.1 Air Quality and Meteorological Monitoring 171
  6.3.2 Surface and Ground Water Monitoring 171
  6.3.3 Solid Wastes 171
  6.3.4 Revegetation 172

FIGURES

2-1 Locations of Potential Oil Shale Developments - Piceance Basin, Colorado . . . 8
2-2 Locations of Potential Oil Shale Developments - Uinta Basin, Utah 9
2-3 Perspective Drawing of Oil Shale Room and Pillar Mining 11
2-4 Vee-Cut Blasting Pattern for Underground Oil Shale Mining . . . 13
2-5 Typical Bench Blasting Pattern Viewed from Above - Tract C-a . 15
2-6 Cross Section of Typical Bench Blasting Pattern Viewed from the Side . . . 16
2-7 Typical Bench Development Viewed from Above - Tract C-a 17
2-8 30-Year Pit Cross Section - Tract C-a . . . 18
2-9 Schematic of Occidental Modified In-Situ Mining Method 20
2-10 Oil Shale Feed Preparation Schematic . . . 21
2-11 Schematic of the TOSCO II Retorting Process . . . 25
2-12 Schematic of Paraho Direct Mode . . . 29
2-13 Schematic of Paraho Indirect Mode . . . 30
2-14 Side View of Union B Retort . . . 31
2-15 Flow Diagram for Union B Retorting Process . . . 34
2-16 Top View of Superior Retort . . . 37
2-17 Cross Section View of the Superior Retort . . . 38
2-18 Schematic of the Occidental Modified In-Situ Process 43
2-19 Flame Front Movement in the Occidental Modified In-Situ Process 44

4-1 Location of Selected Stream Gaging Stations and Oil Shale Developments . . . 115
4-2 Aerial View of Colony Development Operation Disposal Site - Davis Gulch . . . 132
4-3 Tract C-a Conceptual Phase I Solid Waste Disposal Plan 134
4-4 Tract C-a Conceptual Phase II Solid Waste Disposal Plan 135
4-5 Schematic of Union Oil Company Retorted Shale Disposal Plan for Operations at Parachute Creek Site . . . 136
4-6 Backfilling of Mined Out Shale Zone with Processed Shale - Superior Oil Company . . . 139

TABLES

2-1 Results of Federal Oil Shale Lease Offerings 47
2-2 Tract C-a - Rio Blanco Oil Shale Project Summary 49
2-3 Tract C-b - Roxana Oil Shale Project Summary 51
2-4 Tracts U-a/U-b - White River Shale Project Summary 54

3-1 The Sources and Nature of Atmospheric Emissions from Oil Shale Extraction and Processing 61
3-2 Comparison of Total Sulfur in Raw Retort Gases 63
3-3 Comparison of TOSCO II Emissions Inventories (8000 m^3/day) (50,000 bbls/day). 69
3-4 Lease Tract C-a Phase II Emissions Inventory (56,000 bbls/day) . 70
3-5 Lease Tracts U-a/U-b Emissions Inventory (50,000 bbls/day) . . . 71
3-6 Union B Fuel Gas Combustion Emissions 72
3-7 Summary of Air Pollution Control Technology for Oil Shale Preparation and Retorting, and Shale Oil Upgrading 74
3-8 Potential Fugitive Dust Emissions 75
3-9 Estimates of Process Water Requirements for Full Scale Oil Shale Production (m^3 of water needed per m^3 of oil produced) 77
3-10 Water Consumption Requirements for Unit Processes Associated with Oil Shale Processing 77
3-11 Approximate Composition of TOSCO II Combined Process Wastewater (8000 m^3/day upgraded shale oil production) 81
3-12 Paraho (GCR) Process Wastewater Analysis 82
3-13 Approximate Composition and Flow Rates for Selected Wastewater Streams Lease Tracts U-a/U-b (Phase III, 8000 m^3 upgraded shale oil/day) 84

3-14 Ash Composition of Typical Retorted Oil Shales 88
3-15 Properties of Retorted Shales 89
3-16 Inorganic Ions Leachable from Freshly Retorted Shales (kgs/tonne) Based on Laboratory Tests 90
3-17 Levels of Benzo(a)pyrene (BaP) Reported in Selected Natural and Industrial Materials 92

3-18 Typical Composition of Shale Oil Coke 93
3-19 Major Solid Wastes from TOSCO II Processing 95
3-20 Solid Wastes Generated During Construction and Operation of Shale Oil Facilities at Tracts U-a/U-b - Phase IV 96

4-1 Existing Air Quality Data Summary for Federal Oil Shale Lease Tracts 102
4-2 A Comparison of Air Pollutant Emissions (kg per hour) Used in Modeling Studies 110
4-3 Comparison of Modeling Results with Applicable Standards 112
4-4 Water and Dissolved Solids Discharge at Selected Stations in Upper Colorado River Basin 114
4-5 Summary of Piceance and Yellow Creek Streamflow Records 116
4-6 Summary of Roan and Parachute Creek Streamflow Records 117
4-7 Maximum Values for Dissolved Constituents of Surface Waters on and Around Federal Oil Shale Lease Tracts 118
4-8 Mean Values for Dissolved Constituents in Ground Water on Federal Oil Shale Lease Tracts C-a and C-b 121

5-1 Summary of Crude Shale Oil Properties 150
5-2 Summary of "On Site" Upgrading of Shale Oil Planned at Development Sites 152
5-3 Comparable Carcinogenic Potency of Complex Mixtures 156

6-1 Summary of Meteorology and Air Quality Monitoring and Studies. . 161
6-2 Summary of Surface and Ground Water Monitoring Activities . . . 162
6-3 Summary of Spent Shale/Solid Waste Disposal Projects 164
6-4 Summary of Revegetation Projects 165

SUMMARY OF METRIC/ENGLISH UNIT EQUIVALENTS

Energy

1 Btu = 2.929×10^{-4} kilowatt hour (kWh)
1 kcal = .397 Btu

Length

1 inch = 2.54 centimeter (cm)
1 foot = 0.3048 meter (m)
1 yard = 0.9144 meter (m)
1 mile = 1.609 kilometer (km)

Weight

1 pound = 0.4536 kilogram (kg)
1 ton (short) = 9.072×10^2 kilogram (kg)
1 tonne = 1 metric ton (tonne)

Area

1 acre = 0.407 hectare (ha)
1 acre = 4.047×10^3 square meter (m^2)
1 square foot = 9.290×10^{-2} square meter (m^2)
1 square mile = 2.59 square kilometer $(km)^2$

Volume

1 cubic foot = 2.832×10^{-2} cubic meter (m^3)
1 gallon = 3.785×10^{-3} cubic meter (m^3)
1 barrel = 0.1590 cubic meter (m^3) = 42 U.S. gallons
1 acre-foot = 1234 cubic meters
1 cubic yard = .764 cubic meter (m^3)

Conversions especially important in this report:

- Shale oil--1 m^3 = 6.3 barrels =0.93 tonnes crude shale oil
- Volumetric flow rates--1 m^3/sec = 2120 ft^3/min
- Emission factors--1 lb/10^6 Btu = .1145 kg/kcal
- Heating value--890 kcal/m^3 = 100 Btu/SCF
- Oil shale yield--0.125 m^3/tonne = 30 gal/ton
- Water resources--1234 m^3 = 1 acre-foot

1.0 INTRODUCTION AND SUMMARY

Commercial interest in the extraction and processing of oil shale has been shown for several decades. A viable oil shale industry has been "about to start" several times in this century, but each time economic, technical, political, or legal roadblocks have postponed actual development. More recently, the impetus to develop domestic energy sources has prompted many new government and privately sponsored oil shale activities. This apparent increased interest in oil shale has also led to increased concern about environmental impacts which might be associated with large scale extraction and processing operations.

The oil shale area of northwestern Colorado and northeastern Wyoming has no large human population or industrial base at present, and thus air and water quality are not unduly influenced by human activities. Large-scale construction and operation of oil shale facilities, however, will result in direct atmospheric emissions, and wastewater and solid waste generation. Further, an influx of shale industry employees and support services population will create numerous indirect impacts on air, water, and land resources.

The Environmental Protection Agency is empowered to encourage and promote the development of pollution control technology for industrial waste streams. Such technology includes not only "add on" devices for minimizing emissions and effluents, but also "in house" and management techniques for controlling pollution or averting undesirable environmental effects of industrial activities. To aid in defining the need and priorities for control of waste streams associated with oil shale development, EPA has requested the preparation of this preliminary environmental assessment. Included are a summary of current oil shale technologies and development activities, a review of the properties, sources and quantities of wastes which may be generated by these technologies and activities, a discussion of potential environmental impacts and hazards resulting from oil shale development, and discussions of pollution control technology and/or management practices which have been developed or are planned for commercial operations. Some of the current baseline environmental monitoring and control technology development projects are discussed and briefly evaluated. Indirect impacts resulting from population influx into the oil shale region are not discussed in this report, although the relative importance of such impacts should not be minimized. The preliminary environmental assessment will be updated in the final assessment report which will be submitted by TRW/DRI to EPA in June of 1977.

Several oil shale mining and retorting technologies are approaching the commercial state of development. Oil shale has been mined on a modest scale for over three decades. To date, however, mining has been underground and confined to the southern end of the Piceance Basin, with adit access at the

Mahogany zone outcrop. Current development plans for larger scale oil shale extraction call for both room and pillar mining and for open pit mining. Individual developers envision the mining of from 10,000 to over 100,000 tonnes of oil shale per day.

The private sector has developed both above-ground and in-situ retorting technologies, and several companies plan to apply these technologies on privately owned oil shale lands in Colorado and Utah. Similar technologies are likely to be utilized on federally leased oil shale lands. Crude or upgraded shale oil production rates of 1200 to over 8000 m^3 (8000 to over 50,000 bbls) per day are envisioned. Above-ground retorting processes which have reached the stage of industrial interest in the United States may be divided into three classes based upon the way heat is supplied to the retorting process. These categories include retorts using (a) recycled hot solids (e.g., TOSCO II and Lurgi-Ruhrgas, (b) an internal combustion zone within the retort (e.g., Paraho Direct Mode, Superior Circular Grate), or (c) an external, fuel-fired furnace or gasifier (Union Retort B, Paraho Indirect Mode). The major U.S. retorting processes which employ these various modes of heat transfer are individually discussed in Chapter 2 of this report. Although private developers such as the Colony Development Operation, Union Oil Company, and the Paraho Group consider their respective retorting technologies to be demonstrated at the pilot and/or prototype stage,full scale commercial operations are not currently planned or such plans have been postponed. Among the reasons cited for the cautious approach to commercial development are the lack of a definite federal energy policy, uncertainties regarding both production costs and product prices, questions about the ability to meet ambient air quality standards, and the threat of environmental litigation.

Although in-situ extraction of shale oil has attracted research interest for over 20 years, only recently has commercial interest emerged. The Occidental Petroleum Corporation has developed a modified in-situ process and claims that commercial production is technically and economically possible. Several other private interests, as well as the Laramie Energy Research Center (ERDA), are supporting or have proposed in-situ extraction projects.

Chapter 2 includes a summary of the development plans for the federal lease tracts in Colorado and Utah. The developers of Tracts C-a, C-b, and U-a/U-b have recently submitted Detailed Development Plans for their respective tracts to the Area Oil Shale Supervisor (AOSS), as required by the lease stipulations. Each lessee has also, however, requested suspension of certain lease conditions, including tract development requirements for the immediate future. The Department of the Interior has recently granted all of these suspension requests for a period of one year.

In 1975 the Department of the Interior accepted nominations of tracts to be leased for in-situ development. Four of the tracts nominated by industry were recommended by a special committee of the Oil Shale Environmental Advisory Panel. The Secretary of the Interior has not acted to date on the recommendations. An environmental impact statement is currently in preparation.

Chapter 3 of the report is a summary of the types, sources, properties, and quantities of wastes which may be generated during the extraction and processing of oil shale. Of the atmospheric emissions from oil shale processing activities, the major source of SO_2, NO_x, and CO is fuel combustion for process heat. SO_2 is also emitted in the tail gases of sulfur recovery operations. The use of fuel oils in mobile equipment and in explosives results in emissions of CO and NO_x. Hydrocarbons are present in both combustion emissions and in product storage tank vapors. Emissions of particulate matter can result from blasting, raw and retorted shale handling and disposal, shale dust in flue gases, fuel combustion, and site activities which generate fugitive dust.

Emissions of hazardous substances may occur during the extraction and processing of oil shale. Silica (quartz) may be present in dust derived from oil shale and associated rocks and in fugitive dust. Particulate emissions from fuel combustion and fugitive dust from retorted shale handling and disposal could contain small quantities of hazardous organic material and certain trace metals. Retorted shale may release ammonia, hydrogen sulfide, and volatile organics during moisturizing and subsequent cooling. Catalyst materials may release metals to the atmosphere during regeneration, handling, or final disposal.

The quantities of atmospheric emissions associated with shale processing depend on the size of the operation, the type of mining and retorting technology employed, the extent of on-site upgrading, and the degree of emissions control practiced. Emissions inventories for the Colony Development Operation and for Tracts C-a, C-b, U-a/U-b are reported in Section 3.1. Less complete emissions data are presented for the proposed Union Oil Company and Occidental Oil Company operations, and for fugitive dusts which may result from site use activities.

Water is a necessary resource for the development of an oil shale industry. Water would be used for cooling, dust control, gas cleaning and process emissions control, and for moisturizing retorted shale. As much as 3.7 m^3 of water is required for the production of 1 m^3 of upgraded shale oil. Unlike their counterparts in the petroleum, by-product coke, and related industries, oil shale developers do not plan to discharge wastewater directly to local surface water. Rather, process waters would be reused for purposes requiring progressively lower quality water within the plant, and finally for moisturizing retorted shale.

The sources and properties of process wastewaters are discussed in Section 3.2. Generally, the characteristics of these wastewaters are similar to those encountered in petroleum refining - high dissolved and suspended solids, and high chemical and biochemical oxygen demand. Oil and grease, reduced nitrogen and sulfur containing compounds, and organic compounds such as phenolics and carboxylic acids are likely to be present in such waters. Constituents in wastewater applied to retorted shale may be an indirect source of water pollution if mobilization occurs via erosion, runoff, or leaching of a retorted shale disposal pile.

The major solid wastes from oil shale processing are raw shale fines from crushing and dust control, and the processed shale remaining after retorting. In an integrated facility, these constitute more than 95 percent of the solids requiring disposal. The quantity and nature of other solids to be discarded depend primarily upon the extent of upgrading of the crude shale oil which is carried out in conjunction with the retorting operations, and the solid wastes from auxiliary operations. The latter might include shale coke from delayed coking; spent catalysts from hydrotreating, sulfur recovery, and arsenic removal; lime and alum sludges from water treatment; spent activated carbon and diatomaceous earth from oil or gas treatment. The quantities of these wastes which may be generated by various developments are tabulated in Section 3.3.

With many retorting technologies (e.g., TOSCO II and Union B) an organic residue remains on the oil shale after retorting. Other technologies (e.g., Paraho Direct Mode) have been designed to burn most organic material as part of the retorting step. Retorted shale exhibits cement-like properties if most of the carbonaceous material has been burned off during retorting, and such properties may be used to advantage in creating an impermeable disposal pile. On the other hand, carbonaceous retorted shales do not generally exhibit such cementing properties. Inorganic constituents of both burned and carbonaceous retorted shales are partially water soluble, and may be mobilized by water run-off or by percolation through a disposal pile. Carbonaceous retorted shales contain organic substances which may also present a hazard during handling and disposal, or may be present in fugitive dust or leachate waters from disposal piles.

Chapter 4 is a summary of the major potential impacts which can result from oil shale development. The scope of the chapter is limited to direct and indirect impacts on air and water quality resulting from extraction and processing activities. Effects of increased human population (e.g., vehicle traffic) and effects of development on biota are not considered.

Several air quality modeling efforts have been undertaken to predict the impact of process emissions on ambient air quality. Section 4.1 reviews these efforts, including those performed by the developers of the federal lease tracts, for the adequacy of the data inputs and the models employed. Currently, most air quality levels in the oil shale region are well below the federal and state ambient standards, with the exception of occasional short term particulate and oxidant levels. Maximum ambient levels of sulfur dioxide and carbon monoxide associated with individual oil shale operations are predicted to meet state and federal standards. However, suspended particulate and non-methane hydrocarbon levels are predicted to exceed short term standards for significant deterioration and maximum allowable increment increases. Further, emissions assumed in most of the modeling efforts have generally not accounted for fugitive dust, secondary sources such as vehicular traffic, or transient releases.

Potential effects of extraction and processing activities on the quality and flows of the surface and groundwater are discussed in Section 4.2. Existing water quality in the oil shale region varies geographically and seasonally. Several streams and shallow aquifers provide water suitable for irrigation purposes although water quality in lower oil shale aquifers in the Piceance Basin and in the lower reaches of Piceance Creek exceeds the dissolved solids, fluoride, or boron criteria for domestic or irrigation uses. The only significant quantity of water found on or near the Utah lease tracts (U-a/U-b) is that in the White River. Water quality in the White River is suitable for irrigation use except during low flow in the summer.

Withdrawal of good quality surface and groundwater from sources in the upper Colorado Basin for consumptive use may result in increased salinity levels in the lower Colorado River. Conversely, consumptive withdrawal of poor quality groundwater which might otherwise reach the upper Colorado River or its tributaries may result in decreased salinity levels in the lower Colorado River. The exact impact of withdrawal on the Colorado River is not known, but the estimated maximum increase in total dissolved solids at Imperial Dam resulting from a 160,000 m^3 (1,000,000 bbl) per day oil shale industry is only about 15 mg/l, or 1.7% of the current value of TDS at that point.

All of the major developers have indicated their intention to discharge no wastewaters directly to surface streams. All process waters would be reused and ultimately applied to retorted shale. Effects of extraction and processing activities on local hydrology and water quality are therefore likely to be of an indirect or incidental nature. Generally, the water pollution implications of mine dewatering and of the creation of large retorted shale disposal piles are not currently known, and perhaps cannot be known until development occurs. The site specific water pollution problems and proposed water management programs of the Superior Oil Company, Occidental Oil Company, and lessees of the federal tracts are summarized in Section 4.2.

Section 4.3 is a summary of solid waste disposal plans for major oil shale developments, and a review of physical hazards and intermedia pollutant transfer potential of retorted shale disposal piles. Most of the developers propose to use canyon sites for solid waste disposal, and plan to establish stable slopes and water diversion features on the waste piles. The surface of the piles are to be revegetated and retention structures to be built to prevent contaminated waters from reaching surface or groundwater.

In general, retorted shale cannot be entirely returned to mined-out areas as a disposal method since retorted shale occupies a greater volume than the raw shale from which it was derived. The Superior Oil Company, however, proposes to return all of the processed shale from its oil and mineral extraction operations to the mined out zone. In this case, the recovery of sodium and aluminum minerals in addition to shale oil results in a processed shale whose volume is less than that of the parent shale.

The major potential problems for surface disposal of retorted shale are (1) physical instability allowing mass movements; (2) runoff and leaching of retorted shale creating indirect water pollution; and (3) surface destabilization allowing excessive wind and water erosion to occur. These problems or hazards and some experiences with small scale disposal pile stabilization efforts (physical and vegetative) are reviewed in Sections 4.3.2 and 4.3.3.

Shale derived oils have properties different from petroleum derived oils, and different processing steps may be required to produce suitable petroleum substitutes. The composition and properties of shale oils which may influence upgrading steps, refining waste streams, and combustion emissions are discussed in Chapter 5. A brief summary of two experiences in refining crude shale oil is also included. Section 5.2.C is a review of epidemiological studies, analytical measurements, and bioassay tests which have been aimed at determining the carcinogenicity hazard associated with human exposure to crude and refined shale oils.

Chapter 6 is a summary of environmental monitoring projects and studies which have been or are being conducted in the Piceance and Uinta Basins relevant to oil shale development. Such programs may be divided into two general categories: (1) private and/or specialized projects and (2) projects connected with the Federal Prototype Oil Shale Leasing Program. The chapter includes a catalog of various monitoring activities, a narrative summary of the monitoring programs of the lease tracts, and comments about monitoring programs, with focus on scope, quality, and the availability of data and results to interested parties.

2.0 THE STATUS OF OIL SHALE TECHNOLOGIES AND DEVELOPMENT ACTIVITIES

Several oil shale mining and retorting technologies are approaching the state of economic feasibility. The private sector has developed mining, above-ground retorting and in-situ retorting technologies, and several companies plan to apply these technologies on privately owned lands in Colorado and Utah. Similar technologies are likely to be applied on federally leased oil shale lands. This chapter is a brief review of oil shale extraction and retorting technologies. The discussion includes the history, technology, development plans, and some environmental programs of the major contenders for commercial development at present.

The locations of potential oil shale development sites in the Piceance and Unita Basins of Colorado and Utah are shown in Figures 2-1 and 2-2.

2.1 THE EXTRACTION AND PREPARATION OF OIL SHALE FOR RETORTING

Oil shale has been mined on a modest scale for several decades. To date, however, mining has been underground and confined to the southern end of the Piceance Basin with adit access at the Mahogany zone* outcrop. Considerable experience in room and pillar mining has been accumulated.

Current development plans for larger scale oil shale extraction call both for room and pillar mining and for open pit mining. This section reviews the history of oil shale mining, the status of mining technology at present, planned research and development programs, and technology for preparation of shale for retorting.

2.1.1 History (1,2)

Oil shale property was purchased as early as the 1920's for possible development. However, actual oil shale development efforts were not conducted until the Bureau of Mines Shale Research Facility at Anvil Points Colorado was established under the Synthetic Liquid Fuels Act of April 5, 1944. The plant and underground mine were operated by the Bureau of Mines during the period from 1944 through 1956. Authority to lease the facility was given to the Secretary of the Interior in 1956, and from 1964 through 1968 the facility was leased to the Colorado School of Mines Research Foundation for purposes of improving retorting technology.

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*The Mahogany zone is a rich interval of oil shale strata which extends throughout the Piceance and Unita geologic basins in Colorado and Utah.

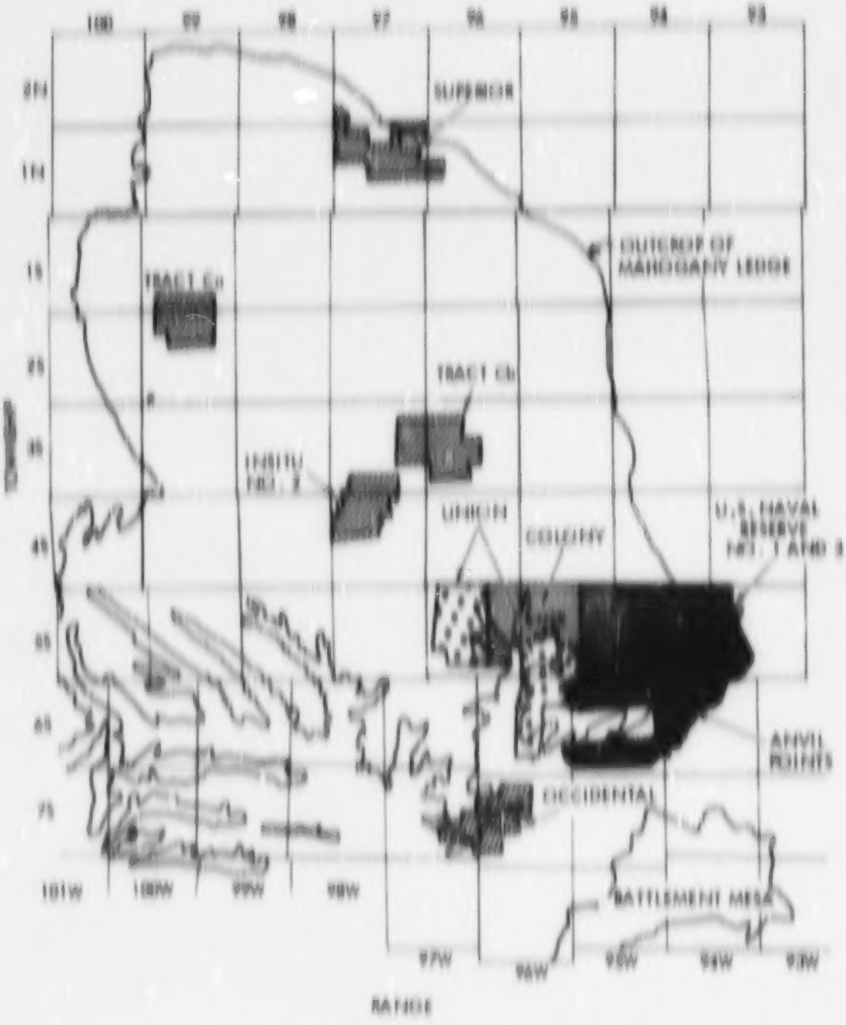
100
99
98
97
96
95
94
93
2N
SUPERIOR
1N
1S
OUTCROP OF MAHOGANY LEDGE
TRACT Ca
2S
TOWNSHIP
TRACT Cb
3S
INSITU NO. 2
UNION
U.S. NAVAL RESERVE NO. 1 AND 3
COLONY
4S
5S
6S
ANVIL POINTS
OCCIDENTAL
7S
101W
100W
99W
98W
BATTLEMENT MESA
97W
96W
95W
94W
93W
RANGE

Figure 2-1. Locations of Potential Oil Shale Developments - Piceance Basin, Colorado

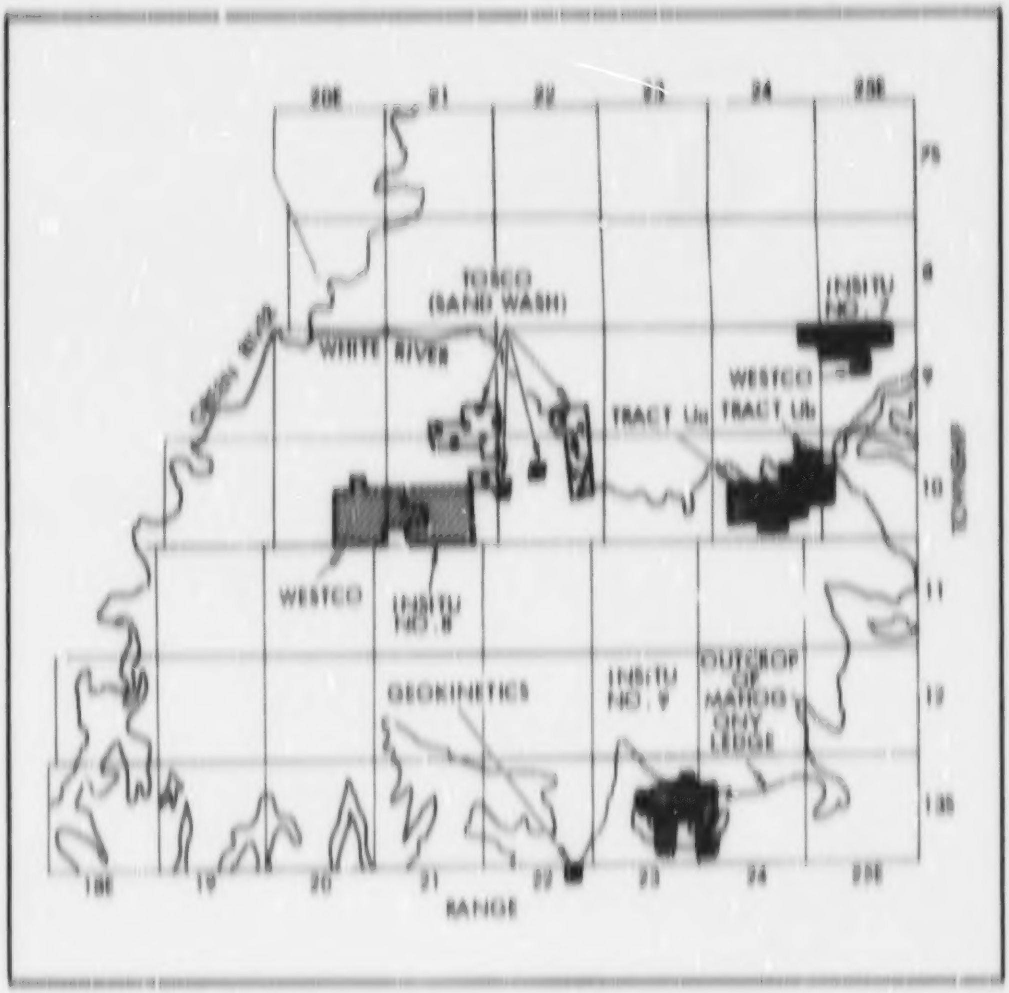
20E
21
22
23
24
25E
7S
8
9
10
11
12
13S
TOWNSHIP
TOSCO (SAND WASH)
GREEN RIVER
WHITE RIVER
INSITU NO. 7
WESTCO TRACT Ub
TRACT Ua
WESTCO
INSITU NO. 8
GEOKINETICS
INSITU NO. 9
OUTCROP OF MAHOGANY LEDGE
18E
19
20
21
22
23
24
25E
RANGE

Figure 2-2. Locations of Potential Oil Shale Developments - Uinta Basin, Utah

Mobil Oil Company acted from 1964 through 1968 as project manager for a six company cooperative effort for improving oil shale technology. At first this group operated the Anvil Points mine and in 1966 opened a new mine in a 24 meter (78 ft) high ledge of the Mahogany zone which produced 453,600 tonnes (500,000 tons). Union Oil Company operated a mine from 1955 through 1958 on their property located on the east fork of Parachute Creek. This effort resulted in the mining of over 56,500 tonnes (70,000 tons) of shale for Union's retort development activities.

The Colony Development operation started with a prototype mining effort in 1964 with the intent of eventually proceeding to a 59,892 tonne (66,000 ton) per day production mine. Operations were suspended in 1973.

The objective of all these efforts, in addition to the production of shale for testing various retorting processes, was to develop applicable methods for mining the richer oil shale of the Mahogany zone. The total years of effort devoted to the development of mining methods in shale have made available reliable systems of ore extraction, a necessary condition for the start of a commercial shale oil industry.

The production systems expected to be used through 1985 are underground room and pillar; open pit (a standard method); and the Occidental modified in-situ method. These mining methods are described below.

2.1.2 Underground Room and Pillar Mining (1,2,3,4,17)

Room and pillar mining is most commonly associated with relatively thin tabular beds of coal and potash. The type of room and pillar mining associated with oil shale is more closely akin to that practiced in the lead-zinc mines of Missouri and Kansas. Once the mine opening has been developed, the basic sequence is as follows (see Fig. 2-3): a) drill, load and blast the upper (approximately 1/2 the thickness mined) heading and ventilate the area; b) bar down dangerous overhead rock; c) muck the blasted oil shale; d) scale the remainder of the loosened shale from the overhead and sides of the ribs and pillars; e) install roof bolts to assure structural integrity for safety in future operations. Mobile units are diesel powered, and carry air compressors for the rotary drills, water for drilling and dust suppression, and lighting systems for operational illumination.

At some distance behind the initial heading development, a similar sequence is followed in the bench area; a) drill, load, blast and ventilate; b) muck; c) scale the pillars and clean up the area for haulage.

Drilling: Rotary drilling jumbos have been developed which are totally self-contained. These units are capable of drilling the necessary 40 to 50, 6.6-12.7 cm (3-5 in) diameter holes rapidly enough to allow loading and blasting a heading in one shift.

Blasting: Ammonium Nitrate/Fuel Oil (ANFO) mixtures of 95/5 composition have proven to be an effective blasting agent for dry holes in oil shale when properly primed. Headings require 0.35 kg of blasting agent per tonne of rock

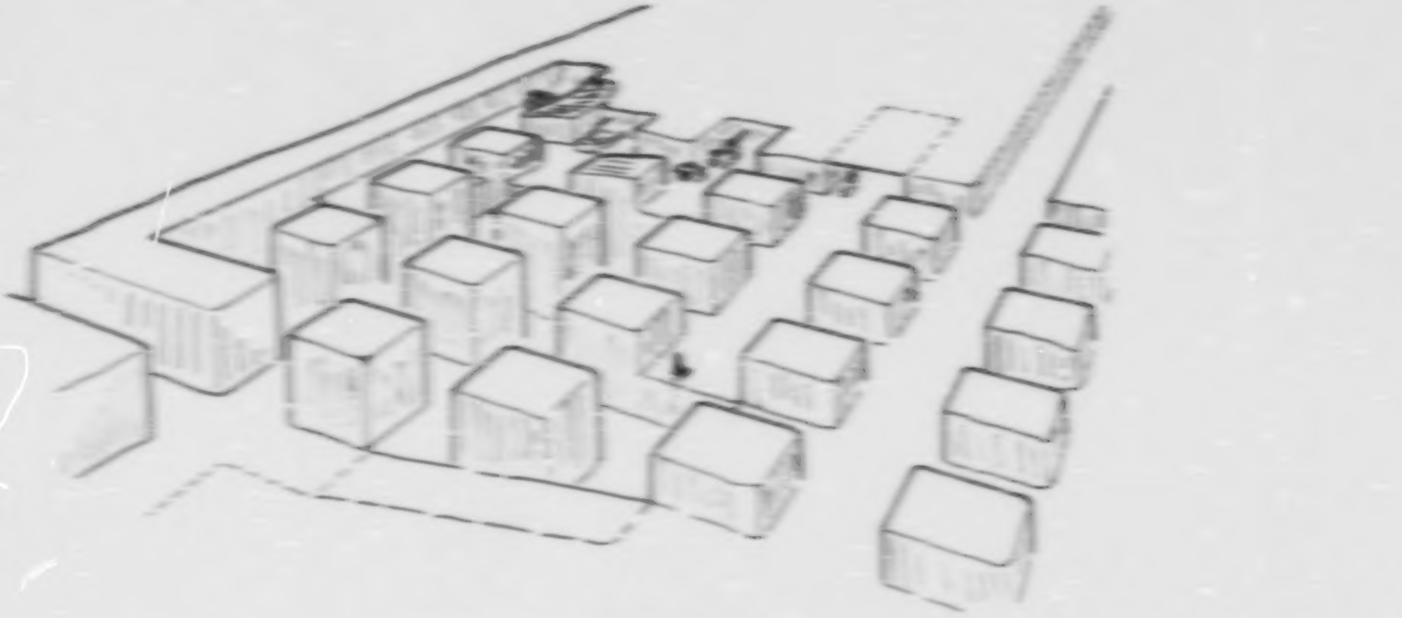

Figure 2-1. Perspective Drawing of Oil Shale Room and Pillar Mining

(0.7 lb/ton). Benches require less explosive - about .175 Kg/tonne (0.35 lbs/ton) because of their easier blasting characteristics.

Blasting in a wide heading is most economically accomplished using a Vee cut (the name is apparent from the view of Fig. 2-4). Since there is only one "free face" to blast to, and the remainder of the area is surrounded by rock which resists movement, a Vee cut requires heavier loading and thus a higher blasting agent factor. In order to open up the blasted area, the shooting is done sequentially from the "cut" holes outward to the "trimmer" holes. Holes may also be sequentially fired from the middle of the face upward and downward, with the bottom row of "lifters" typically being the last fired. This allows the muck to be thrown away from the face for easier loading.

Bench blasting is similar to that associated with open pit mining and will be described in Section 2.1.3.

Ventilating: Ventilation regulations require a minimum of 2.8 m^3/min of air flow (100 cfm) per diesel horsepower. After blasting there is a requirement to reduce the NO_x level in mine air below a Threshold Limit Value (TLV) of 25 ppmv within an hour so that the next shift can work in a safe atmosphere. All fumes and dust generated will generally be rejected to the outside atmosphere in a short period of time.

Barring Down: Before mucking and haulage, safety procedures normally require men working on top of the muck pile to bar down loose rock from the back to prevent rock falls during mucking.

Mucking and Haulage: The practice of room and pillar mining in Colorado oil shale and in the midwestern lead-zinc district has led to the development of diesel front end loaders of 19 m^3 (25 cubic yards) capacity and diesel trucks to 67 tonnes (75 tons) capacity. All diesel engines are equipped with scrubbers to meet mine toxic gas emission requirements. Haulage from the mine is accomplished by trucks or conveyors through adit entry mines. For inclined shafts, conveyors or skips will be used depending on the angle of incline. Skips will be required for operation from vertical shafts.

Roof Bolting and Scaling: As soon as the heading has been mucked out, detailed scaling of the back* and installation of rock bolts is accomplished. A pattern of installing rockbolts on 1.8 m (6 ft) centers has been established for present mines along with a general pattern of 18 m (60 ft) rooms and 18 m (60 ft) pillars. The length of rock bolts will depend upon the thickness and competence of overlying strata.

Shale mine pillars have been instrumented and various surveys have been made of their structural competence. Knowledge of the geological joint system of the oil shale bed has a large influence on the ability to calculate pillar size versus thickness of overburden. Thus, orientation of the mine to take advantage of the geological joint system is important. But, since the oil shale mines developed to date have been of small areal extent, the effect of large scale underground excavation on pillars is unknown.

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*The roof of a hard rock mine is normally referred to as the back.

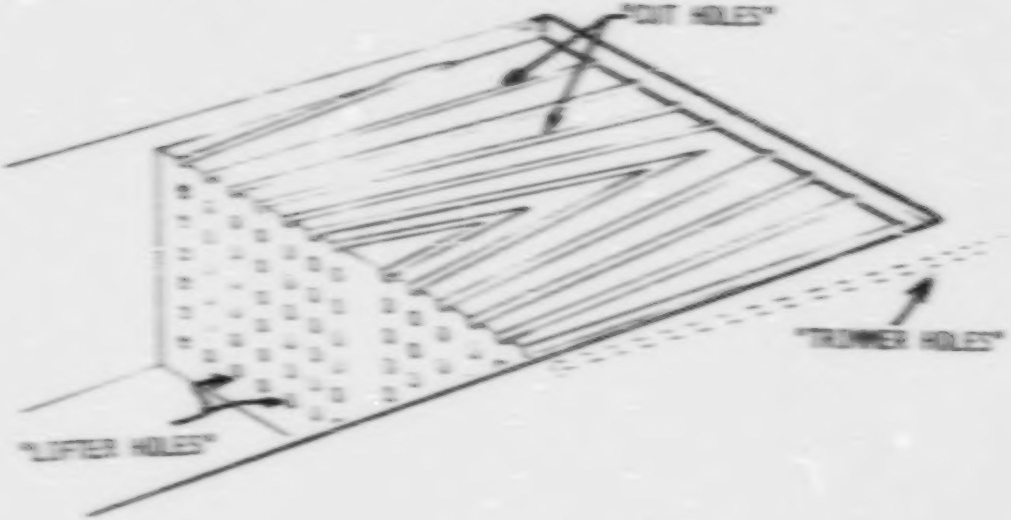

"CUT HOLES"
"TRIMMER HOLES"
"LIFTER HOLES"

Figure 2-4. Vee-Cut Blasting Pattern for Underground Oil Shale Mining

2.1.3 Open Pit Mining (2,5,7)

Open pit mining is not as complex as underground mining, but the basic steps are similar: a) drill, load, and blast either the overburden or the oil shale; b) load the material for transport to the retorting or disposal area; c) scale the face for safety and repeat the cycle.

Drilling: Drilling in open pit mines is normally accomplished with large mobile drills, capable of drilling large diameter holes. Bench height and drill characteristics are usually chosen to obtain a drill with a mast height sufficient to drill a hole in one pass. If achievement of the necessary bench depth requires the addition of lengths of drill stem, the operation would be slowed down. Figure 2-5 shows a view of a drilling pattern planned for a large bench on Tract C-a (7).

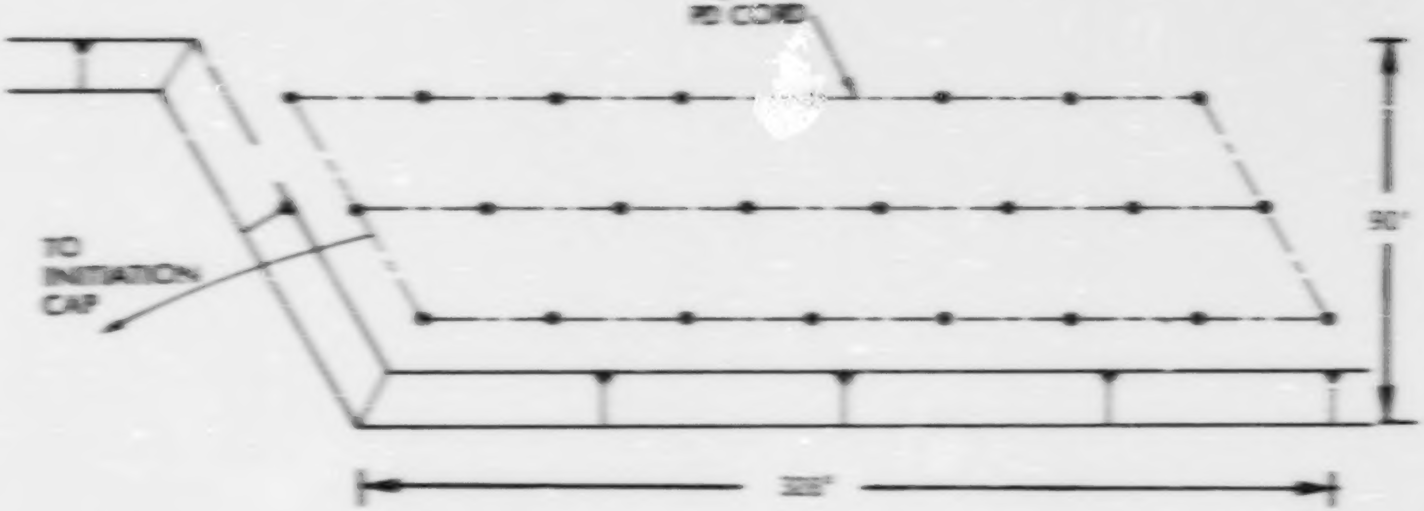
Blasting: Because larger loading equipment can be used on surface than is possible underground, the blasting pattern in a pit mine can be spread out and large powder holes used, even though this may produce larger blocks of ore. An average of 0.35 lbs of ANFO blasting agent per ton (.175 kg/tonne) of material will likely be required, although the quantity can be adjusted as experience with the variations in the oil shale develops. Figure 2-6 shows the cross section of a typical blasting pattern as envisioned for Tract C-a (7). The holes are drilled and loaded below the bench level to preserve a level floor for subsequent operations. Stemming in the top of the hole effectively contains the explosion to maximize useful effects.

In open pit mining, detonating cord is normally used between holes and down the holes to the primers. Millisecond delay connectors are used between sections of cord to sequentially initiate blasts from front to back and side to side. This improves fragmentation as well as minimizing shock to the surrounding area. Since the detonating cord is relatively insensitive to initial detonation, safety is improved. Electrically initiated caps used to start the sequence do not have to be connected until last. If there are thunderstorms and lightning in the area blasting can thus be delayed.

Loading and Hauling: Broken ore is loaded with large shovels (usually electrically powered) into trucks having capacities of up to 77 tonnes (85 ton). Diesel powered front end loaders and bulldozers are used for cleanup in and around the loading areas. Road graders and watering trucks are required to maintain haul roads since tire wear is one of the most expensive operating costs associated with open pit mining.

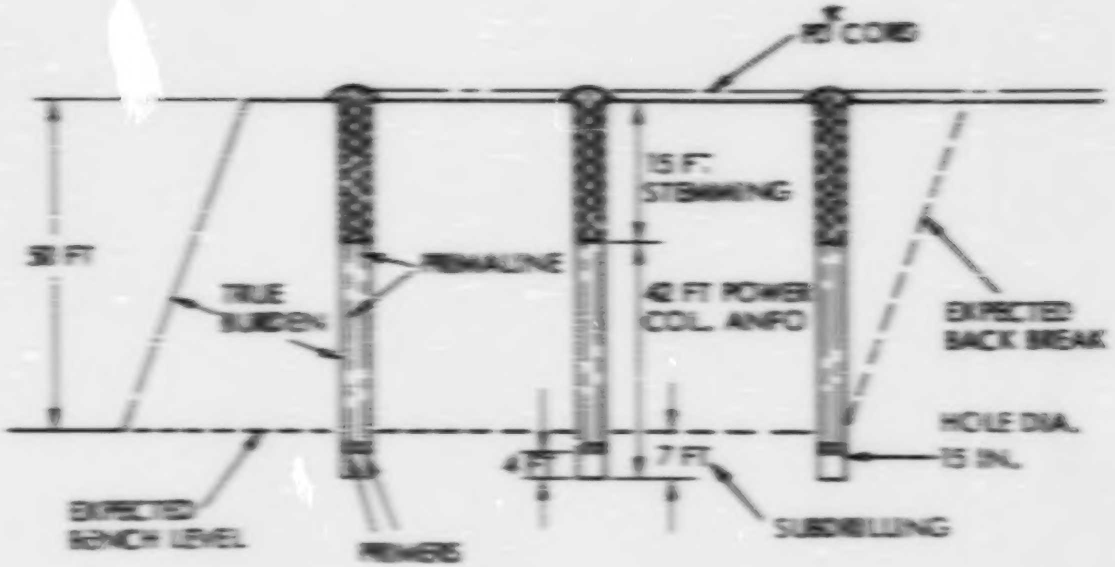
Frequently primary crushing of the ore is accomplished in the open pit, followed by haulage from the pit with either large diesel trucks. Alternatively ore may be transported by conveyor belt to the secondary crushing storage pile. Figure 2-7 shows a schematic plan of a loading operation (7).

Slope Stability: Both the safety of the pit and economics of open pit mining are highly dependent upon the steepness of the side slopes which can be maintained in the pit (see Figure 2-8 where the slope angle is ≈45°). If the slope stability cannot be maintained at a fairly steep angle, slides


PD* CORD
TO INITIATION CAP
90'
320'

*PD = Primary Detonating

Figure 2-6. Typical Bench Blasting Pattern Viewed From Above - Tract C-a (7)


*PD CORD
15 FT.
STEMMING
50 FT
PRIMALINE
TRUE
BURDEN
42 FT POWDER
COL. ANFO
EXPECTED
BACK BREAK
HOLE DIA.
15 IN.
4 FT
7 FT
EXPECTED
BENCH LEVEL
PRIMERS
SUBDRILLING

*Primary Detonating

Figure 2-6. Cross Section of Typical Bench Blasting Pattern Viewed from the Side (7)

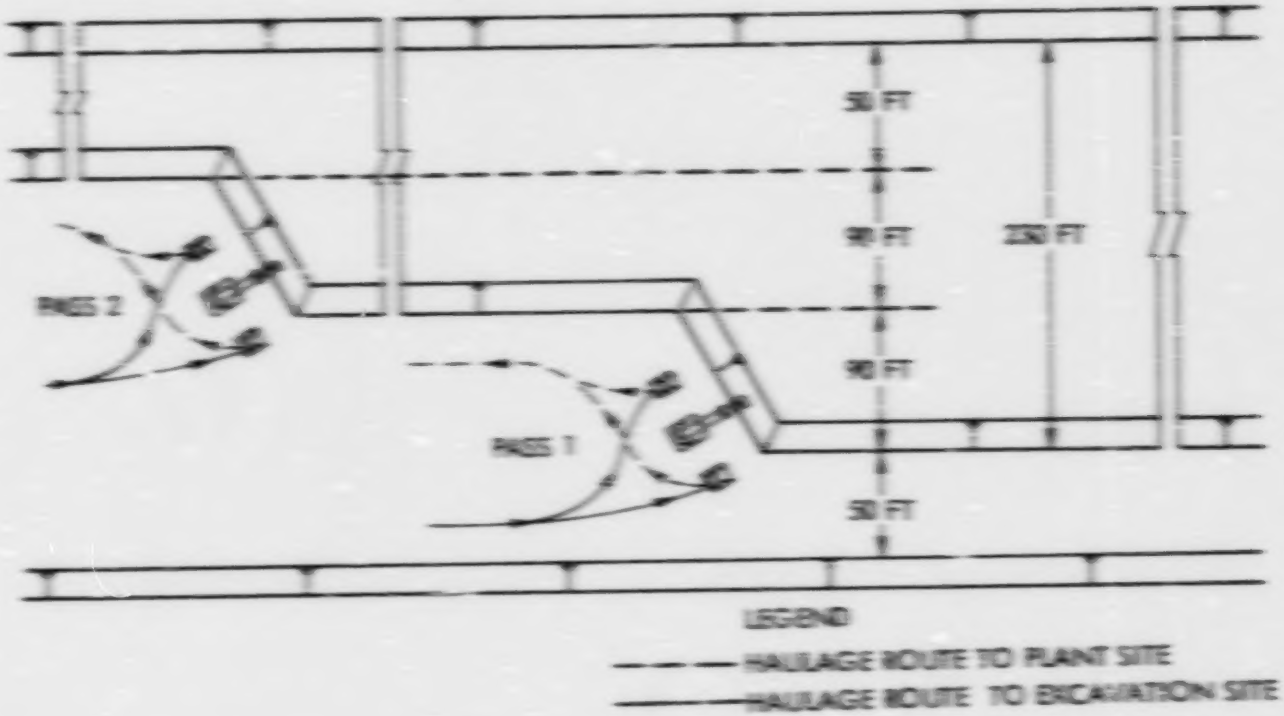

50 FT
90 FT
90 FT
50 FT
230 FT
PASS 2
PASS 1
LEGEND
HAULAGE ROUTE TO PLANT SITE
HAULAGE ROUTE TO EXCAVATION SITE

Figure 2-7. Typical Bench Development Viewed from Above – Tract C-a (7)

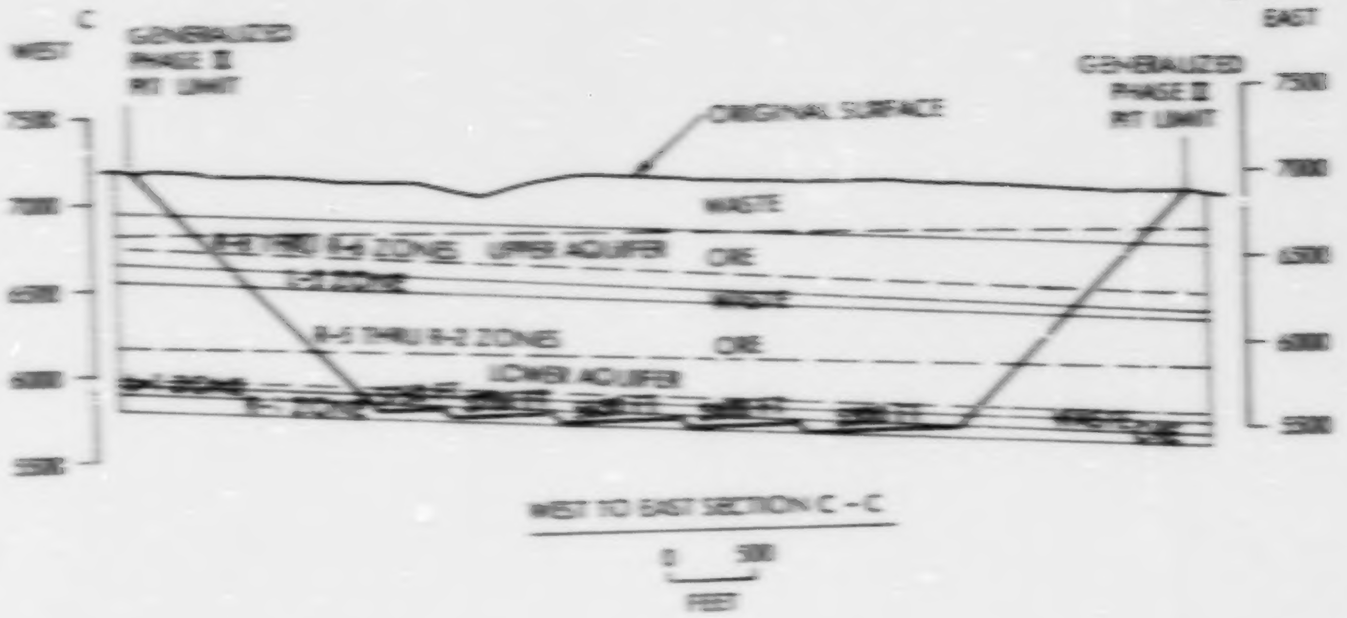

C
WEST
GENERALIZED
PHASE II
PIT LIMIT
C'
EAST
GENERALIZED
PHASE II
PIT LIMIT
ORIGINAL SURFACE
WASTE
UPPER AQUIFER
ORE
WASTE
ZONES
ORE
LOWER AQUIFER
7500
7000
6500
6000
5500
WEST TO EAST SECTION C – C
0
500
FEET

Figure 2-8. 30-Year Pit Cross Section - Tract C-a (7) hazardous to personnel may result. If it is necessary to maintain the slope at low angles to avoid slides, the amount of overburden which must be removed compared to the amount of usable oil shale produced could make the operation too expensive.

2.1.4 Mining for In-Situ Retorting (8)

A general discussion of in-situ retorting can be found in Section 2.3. Of interest here is the Occidental modified in-situ operation near De Beque, Colorado. As described in Section 2.3, mining is performed at two levels. The layer between these levels is drilled and blasted to form a room or "chimney" filled with rubblized shale for retorting (Figure 2-9). The chimneys are planned to be about 95 meters high and 30 meters square.

Since large cross-section chimneys are desirable from a resource recovery point of view it is probably necessary to leave pillars in both the upper and lower levels for safety during mining. These pillars would be blasted at the same time as the main column and form part of the rubblized column for retorting. Though a chimney would be partially filled with retorted shale, the long span across the tops of a chimney would make subsidence more likely than in the case of normal room and pillar mining.

2.1.5 Advanced Mining Methods

The Bureau of Mines contracted with several companies for studies of advanced mining methods (10). The contracts were with Cameron Engineers for underground mining methods, Fennix and Scisson for modified in-situ methods, and Sun Oil Company for single pass open pit mining methods.

Cameron Engineers examined eight underground mining systems for mining thick shale under heavy overburden (9). Of the eight systems examined, four were considered acceptable. In order of preference they were chamber and pillar, sublevel stoping with spent shale backfill, sublevel stoping with full subsidence, and block caving to slusher drifts.

Fennix and Scisson examined ten basic mining system possibilities and selected four candidate rubblization techniques for modified in-situ retorting based upon two mining systems, room and pillar and tunnel boring (11). The rubblization techniques examined were raise boring, vertical drill and blast, fan drill and blast, and horizontal ring drill and blast. System II Room and Pillar, Vertical Drill and Blast, System IV Tunnel Boring, and Horizontal Ring Drill and Blast were recommended to the Bureau of Mines for further study in the second phase of the contract.

Sun Oil Company examined a single pass open pit mine (5). The most significant aspect of their efforts was that their rock mechanics calculations indicated that an average 37° slope could be maintained in the area considered.

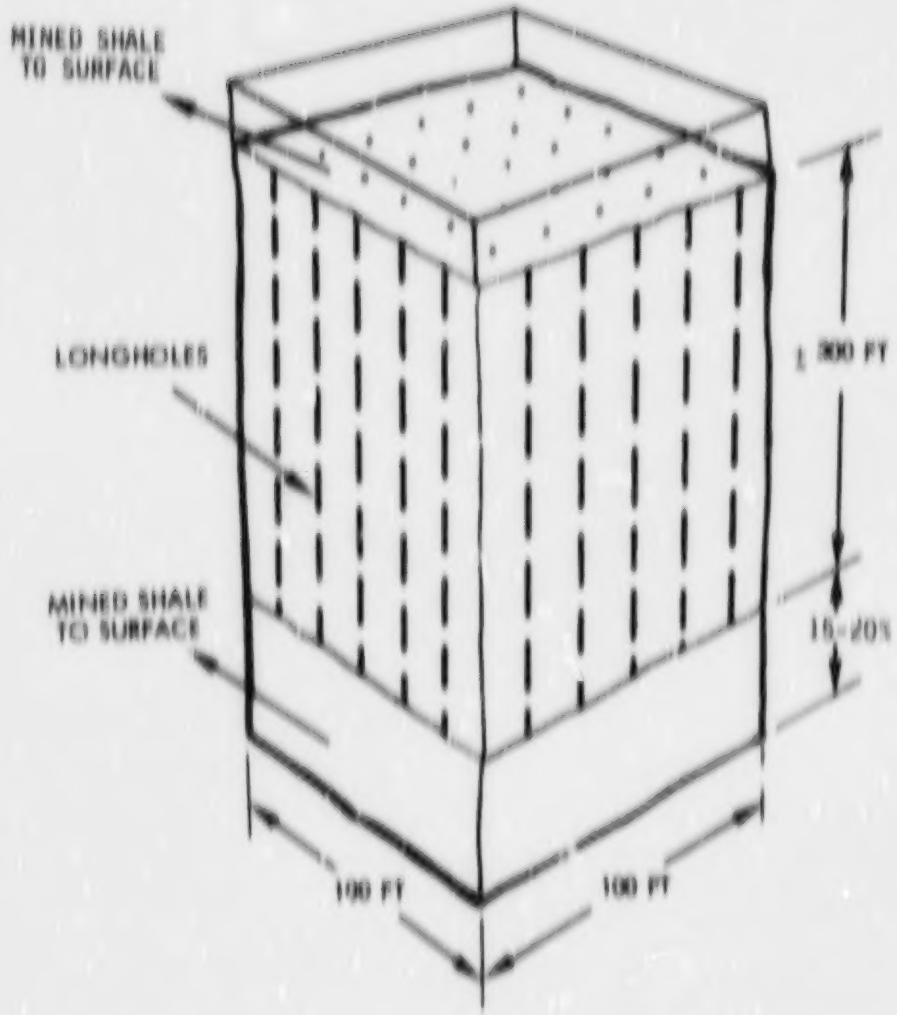

MINED SHALE
TO SURFACE
LONGHOLES
MINED SHALE
TO SURFACE
± 300 FT
15-20%
100 FT
100 FT

Figure 2-9. Schematic of Occidental Modified In-Situ Mining Method

In addition to the above contracted studies, the Bureau of Mines is developing mining technology for the rich, deep oil shales and associated saline minerals of the central Piceance Basin, Colorado (9). One corehole has been drilled in this area, and a second hole, 1.8 m in diameter, is planned to gather additional shaft sinking data in FY 77. Later plans call for sinking a full sized shaft (in FY 78) to develop full technical and economic data for shaft sinking through the saline aquifer system and leached zone strata (10).

2.1.6 Storage, Transport and Crushing of Oil Shale (6,7,12)

Figure 2-10 schematically represents a typical oil shale preparation circuit. The mined shale is fed from trucks or conveyors into a feed surge control hopper(s). From the feed hopper(s) the ore is conveyed to grizzlies above the primary crushers. A grizzly serves the purpose of screening out ore which will choke the entry to the primary crusher and is made of heavy bar. The oversize ore is broken on the grizzly (hydraulic picks are used for this purpose) so that the retained rocks pass the bar screen.

The primary crusher reduces the ore to a size which will fit the entry for the secondary crusher. Primary crushers to be used for oil shale are generally the largest size commercially available and are banked for two reasons: a) the higher reliability of standard units and b) having several units increases the overall system reliability. It is not efficient for a crusher to produce 100% of a product which will feed the next crushing stage because too much undersize material will be produced which may slow the flow through the following crusher). Therefore, the primary crusher product is screened and the oversize portion (10-20%) is returned to the primary crusher feed.

From the primary crusher the ore is moved to a stockpile by covered conveyor. The surface storage required for reliable feed to the retorts is a minimum of a 30-day supply. A stacker-reclaimer is used for stockpiling the ore in windrows and reclaiming it for feeding the secondary crushing circuit.

The secondary crushing circuit is a duplicate of the system described for the primary crushing circuit, except that a grizzly is not required since the ore is already sized to fit the input requirements of the crushers. The size requirements and limitations may be found in the individual process descriptions (see Section 2.2).

Fine ore from the secondary crusher is stored in silos from which the ore is moved by weight belt conveyors to the retorts.

Particulate Emission Control: Emissions and effluents from the various operations are discussed in Section 3. Particulate emissions from crushing have predominant impact potential, and all developers plan to control dust from the crushing operation by use of the best available technology. Crusher buildings are to be negatively pressurized, conveyor belts are to be covered, suction hoods are to be placed over appropriate points and all dust laden air

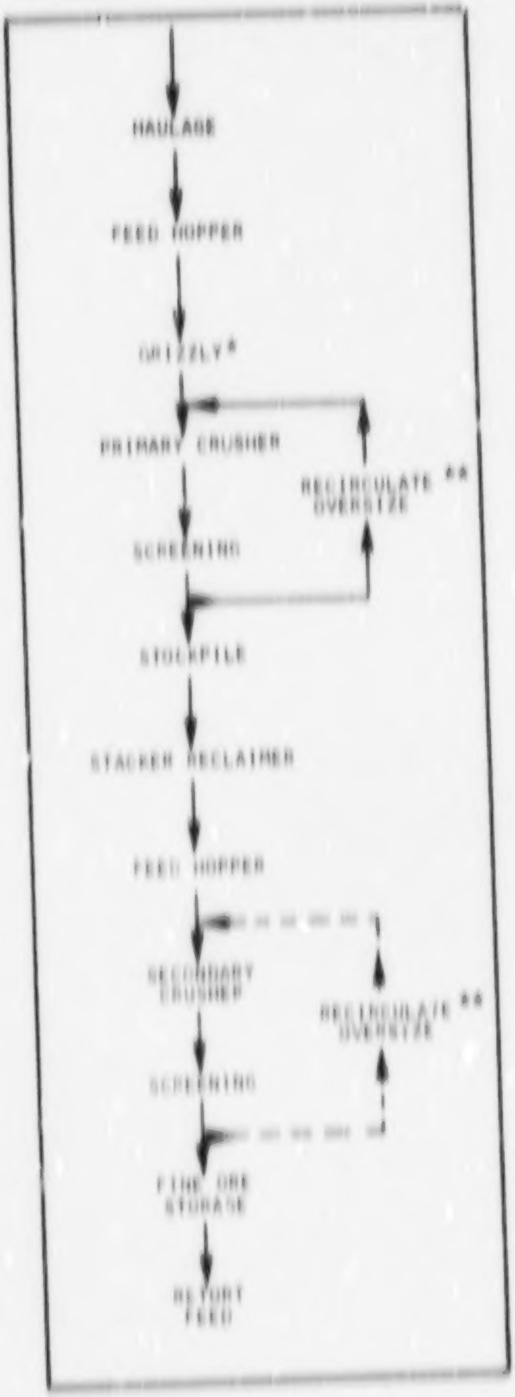

HAULAGE
FEED HOPPER
GRIZZLY*
PRIMARY CRUSHER
RECIRCULATE ** OVERSIZE
SCREENING
STOCKPILE
STACKER RECLAIMER
FEED HOPPER
SECONDARY CRUSHER
RECIRCULATE ** OVERSIZE
SCREENING
FINE ORE STORAGE
RETORT FEED

Figure 2-10. Oil Shale Feed Preparation Schematic

*A bar screening device for retaining and breaking large pieces of rock (~24")
**Oversize depends on the retorting process feed requirements.

is to be fed to bag house (fabric) filters. The collected dust may be fed to retorts which can use fine material or may be mixed with spent shale and placed in the disposal area. Stockpiles will be sprayed with bitumastic or latex preparations to reduce wind blown dust. A review of expected fugitive dust emissions from these sources is also included in Section 3.

2.2 SURFACE RETORTING TECHNOLOGIES AND DEVELOPMENT PLANS

Above ground retorting processes which have reached the stage of industrial interest in the United States may be divided into three classes based upon the manner heat is supplied to the retorting process. These categories include retorts using (a) recycled hot solids, (b) an internal combustion zone within the retort, and (c) an external, fuel-fired furnace or gasifier. Potentially commercial U.S. retorting processes which employ these various modes of heat transfer are individually discussed in the sections to follow. Processes are presented in the approximate order of their technical and commercial advancement.

2.2.1 TOSCO II Retorting Process (Recycled Hot Solids)

History (14): TOSCO II is the process of The Oil Shale Corporation. Initial development work (from 1955 to 1966) was conducted under TOSCO sponsorship by the University of Denver Research Institute, in a 22 tonne/day (24 ton/day) pilot plant. In 1964 the Corporation formed Colony Development Operation, which included SOHIO, Cleveland Cliffs, Atlantic Richfield, and TOSCO. (Later, Ashland Oil and Shell Oil replaced SOHIO and Cliffs.) A 909 tonne/day (1000 ton/day) semi-works plant was constructed near Grand Valley, Colorado, and operated until 1972. The site included a room-and-pillar mine which produced over one million tons of raw shale, and a number of test sites for the study of retorted shale disposal and site revegetation.

This process is probably the closest to immediate industrial scale-up to 8000 m³/day (50,000 bbl/day). It has been dormant since 1974, pending initiation of a federal synfuels participation program and completion of a Final Environmental Impact Statement (EIS).

Process Technology (12,13,14,15): Minus one-half inch crushed shale (including fines) is preheated by direct contact with hot flue gases from a ball heater (see Figure 2-11) used downstream in the process. The preheated shale is then fed to a horizontal, rotating retort, where it is heated to 480° C (900°F) by mixing with small, 1.30 cm (1/2") hot ceramic balls. Shale oil vapors are removed, fractionated and condensed. The cooled balls and retorted (spent) shale are discharged from the retort, and screened to separate the spent shale from the balls. The spent shale is cooled in a rotating drum steam generator, moistened to about 14% water content, and transported to the disposal site. As discarded it normally contains about 4-5% residual carbonaceous matter.

The cooled balls are sent to an external ball heater, reheated, and recycled to the retort. In a typical situation the ball to raw shale feed ratio to the retort is about 2:1. The ball heater can use an outside fuel, a portion of retort off-gases, and/or even the carbonaceous residue on the spent shale as a fuel source(s).

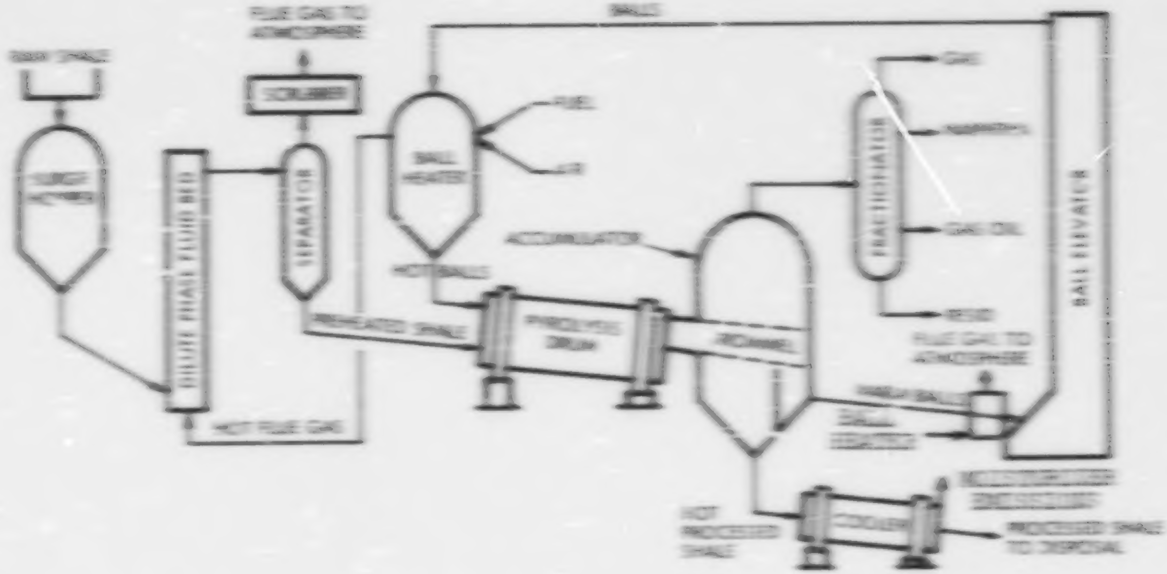

RAW SHALE
SURGE HOPPER
DILUTE PHASE FLUID BED
HOT FLUE GAS
SEPARATOR
SCRUBBER
FLUE GAS TO ATMOSPHERE
BALLS
BALL HEATER
FUEL
AIR
HOT BALLS
PREHEATED SHALE
PYROLYSIS DRUM
ACCUMULATOR
TROMMEL
FRACTIONATOR
GAS
NAPHTHA
GAS OIL
RESID
BALL ELEVATOR
FLUE GAS TO ATMOSPHERE
WARM BALLS
HOT PROCESSED SHALE
COOLER
PROCESSED SHALE TO DISPOSAL

Figure 2-11. Schematic of the TOSCO II Retorting Process (12)

The crude shale oil is fractionated into gas, naphtha, gas oil, and bottoms oil. Subsequent hydrotreating and coking is used to upgrade the products to plant fuel gases and LPG, low sulfur fuel oil, diesel fuel, plus sulfur, ammonia, and petroleum coke byproducts.

TOSCO has presented considerable detail (12,13) regarding proposed pollution control technologies to be utilized throughout its various operations (mining, retorting, upgrading). In the case of the retorting plant, a venturi wet scrubber is to be used for dust control in the shale preheat system, together with settling chambers and cyclones. Hot flue gases in the preheat system will be incinerated prior to discharge, in order to reduce trace hydrocarbons. Warm flue gas and a high energy venturi scrubber will remove residual dust from the ball recirculation system. A foul water stripper will remove most of the NH_3, H_2S, and CO_2 gases from plant waters. Plant fuel gases will be treated to reduce the sulfur and nitrogen present, prior to on-site use for heat generation. H_2S is recovered as elemental sulfur in a Claus Plant, tail gases are treated for trace SO_2 removal in a Wellman-Lord unit. Arsenic is removed from the gas oil and naphtha prior to hydrogenation by a proprietary catalytic process. Emissions from the moisturizing of spent shale are controlled by a venturi wet scrubber.

Development Plans (13). A full-scale commercial plant processing some 55,000 tonnes (61,000 tons) of raw shale per day for 20 years from a 1600 hectare (4,000 acre) underground mine has been designed, together with upgrading facilities. A plant site on upper Parachute Creek has been selected, together with a 325 hectare (800 acre) disposal site in adjacent Davis Gulch. Two 230 kv powerlines may be built by Colorado Public Service Company to service the plant. Permit applications have been made for a 310 km (194 mile) long, 40 cm (16 inch) product pipeline to Lisbon Valley Station, Utah. Access roads and a railroad spur are under construction. A water contract with the U.S. Bureau of Reclamation proposes to divert .35 cubic meters/sec (12.5 ft^3/sec) of water for the plant from the Colorado River at Grand Valley, Colorado.

Annual construction employment is expected to reach 2400 people in the second year of construction. Plant and mine direct employment is estimated to stabilize at 1,000 when full-scale production is attained in the fourth year after project initiation, with an additional 1,000 people involved in peripheral indirect employment.

Recent estimates indicate a grand total investment of $960 million (Sept. 1975 dollars), with a required selling price of $14.20/bbl at a 10% discounted cash flow return on an all-equity investment.

Use of TOSCO II Technology at Sites Other than Parachute Creek (Dow Property). Some 5480 hectares (14,700 acres) of Uintah County land held by The Oil Shale Corporation has been consolidated into the "Sand Wash Unit" (16). The Corporation is committed to expend a minimum of $8 million in predevelopment costs on the site. Room and pillar mining of 10-13m (30-40 ft) of shale at approximately 600 meters (2000 feet) in depth is planned and TOSCO II retorting is to be employed.

TOSCO II retorting may be employed in varying degrees at Lease Tracts C-b, C-a and U-a/U-b.

Environmental Programs: The Colony/TOSCO group has conducted a thorough environmental assessment of its proposed plant. A 20-volume Environmental Impact Analysis for the Parachute Creek Development was published in 1974 (13). A formal BLM prepared Draft Environmental Impact Statement was issued in December 1975 (12). Hearings were held in January 1976. A final EIS is now being prepared. The production of 7500 m^3/day (47,000 barrels) of fuel oil per day is contemplated. Revegetation of the disposal area, as stated by Colony, will be continued for as long as necessary to establish a compatible, stable vegetative cover.

2.2.2 The Paraho Processes (Gas Combustion and Hot Inert Gas Retorting)

History (14,17): The Gas Combustion Retort was initially developed in the U.S. Bureau of Mines at Anvil Points, Colorado in 1951, and reached a 136 tonne/day (150 ton/day) pilot plant-capacity at the conclusion of the Synthetic Liquid Fuels Program in 1955. Between 1964 and 1966, a consortium of six petroleum companies (Mobil, Humble, Pan American, Sinclair, Continental, and Phillips) improved the process, attaining a capacity of 320 tonnes/day (350 tons/day) at yields in excess of 85% of Fischer assay. However, the studies of the consortium indicate that difficulties were encountered with small shale sizes, high rates of gas and shale throughout, and bridging due to rich shales. The Paraho/Development Engineering, Inc. gas combustion retort was designed to overcome such limitations.

The Development Engineering, Inc., (DEI) kiln was invented by John B. Jones (U.S. Patent No. 3,736,247), and initially used for calcining limestone where it has attained a capacity of 636 tonnes/day (700 tons/day) in a 3.2 meter (10.5 ft) diameter design. In May 1972 DEI leased the federal facilities at Anvil Points, Colorado and launched a project to apply the DEI kiln to oil shale retorting. A consortium of 17 companies, known as the Paraho Oil Shale Project was formed, and activities at Anvil Points initiated in late 1973. A 1.4 meter (4.5 ft) diameter pilot kiln was built, followed by a 2.6 meter (8.5 ft) inside diameter semi-works retort with a nominal capacity of 410 tonnes/day (450 tons/day). This latter retort has been operated since 1974, producing 1590 m^3 (10,000 barrels) of shale oil for the Navy in a 56-day continuous run in March 1975. Private financing for the project to date has been $9 million.

It is planned to continue process development for the next 18 to 24 months under a proposed $6 million ERDA/Navy appropriation, while an Environmental Impact Statement is prepared for construction of a full-scale 11,800 tonnes/day (13,000 ton/day) commercial module.

Process Technology Gas Combustion or Direct Mode (14,17,18): The USBM Gas Combustion Retort consisted of a vertical vessel fed from the top with raw shale, which moved downward by gravity through a top preheat zone, thence into a retorted shale cooling zone. Oil vapors from the retorting zone passed upward through the preheat zone, where they condensed to a stable aerosol mist that passed out with the retort gases and were recovered in mist collectors.

Part of the gases released by retorting 700-900 KCAL/m^3 (80-100 Btu/SCF) were recycled near the bottom of the retort, where they were heated and passed upward into the combustion zone. Here, new retort gas was injected and the gases burned, together with a portion of the residual carbon on the retorted shale to furnish the heat for the process.

The Paraho/DEI retort employs the same four-zone configuration and operating methods, but substantial improvements have been made in the design of inlet and discharge mechanisms, and in recycle gas/air introduction to the retort. As a result the remainder of discussion of the gas combustion method in this section will be restricted to the Paraho process.

In the direct mode Paraho process (Fig. 2-12) minus 7.6 cm (3 in) plus 0.6 cm (1/4 in) shale is introduced into the top of the retort through a rotating spreader, passes through the 4 zones previously described, and is discharged through a special, hydraulically operated discharge grate, which more uniformly controls solids flow rates. Retort off-gases (approx. 900 kcal/m^3 or 100 Btu/SCF) are recycled to the retort at three points. These gases, together with combustion of a portion of the carbonaceous residue on the spent shale, provide the heat for the process. The retorted shale containing a 2.3% carbonaceous residue, is discharged to disposal at approximately 150°C (300°F). Retort gases, oil mist, and vapors leave the top of the retort at approximately 66°C (150°F), and pass through a cyclone, wet electrostatic precipitator, and aerial condenser to remove oil. As previously noted, a portion of these gases are recycled to the retort.

Process Technology: The Paraho Indirect Mode Retorting Process (Hot Inert Gas Retorting) (18): The Paraho process may also be operated in the indirect mode (Fig. 2-13), in which case no combustion is carried out in the retort, per se. The retort gases therefore have a high heating value 8000 kcal/m^3 (900 Btu/SCF). A portion of these gases are used to heat a recycle portion of same in an external furnace, and the latter are recycled to the retort as a heat source. The retorted shale has a carbon content of 4.5%. A combination of direct and indirect operating modes may also be employed.

The product shale oil has a 21° API gravity, with pour points of 32°C (90°F, direct mode) or 19°C (68°F, indirect mode). It may be upgraded by conventional hydrotreatment to remove nitrogen and sulfur, and refined to normal petroleum products. No shale oil upgrading has been undertaken at Anvil Points; all product oil is stored for transport elsewhere.

Development Plans (32): It is proposed by Paraho to construct a single, full-size, 11,800 tonnes/day (13,000 tons/day) commercial modular retort at Anvil Points, Colorado, on a site approximately one mile west of the existing Paraho semi-works plant. The present underground room-and- pillar mining facilities will be expanded eastward. Raw shale will be passed through a conveyor system to a 2 hectare (5 acre) retort plant area located on the present mine road approximately 1.2 KM (3/4 mile) southwest of the mine, at an elevation of approximately 2,100 meters (7,000 feet). Retorted shale will be conveyed to the disposal area now being used for the current Paraho operations. Shale oil will be transported by rail or truck to a refinery for processing.

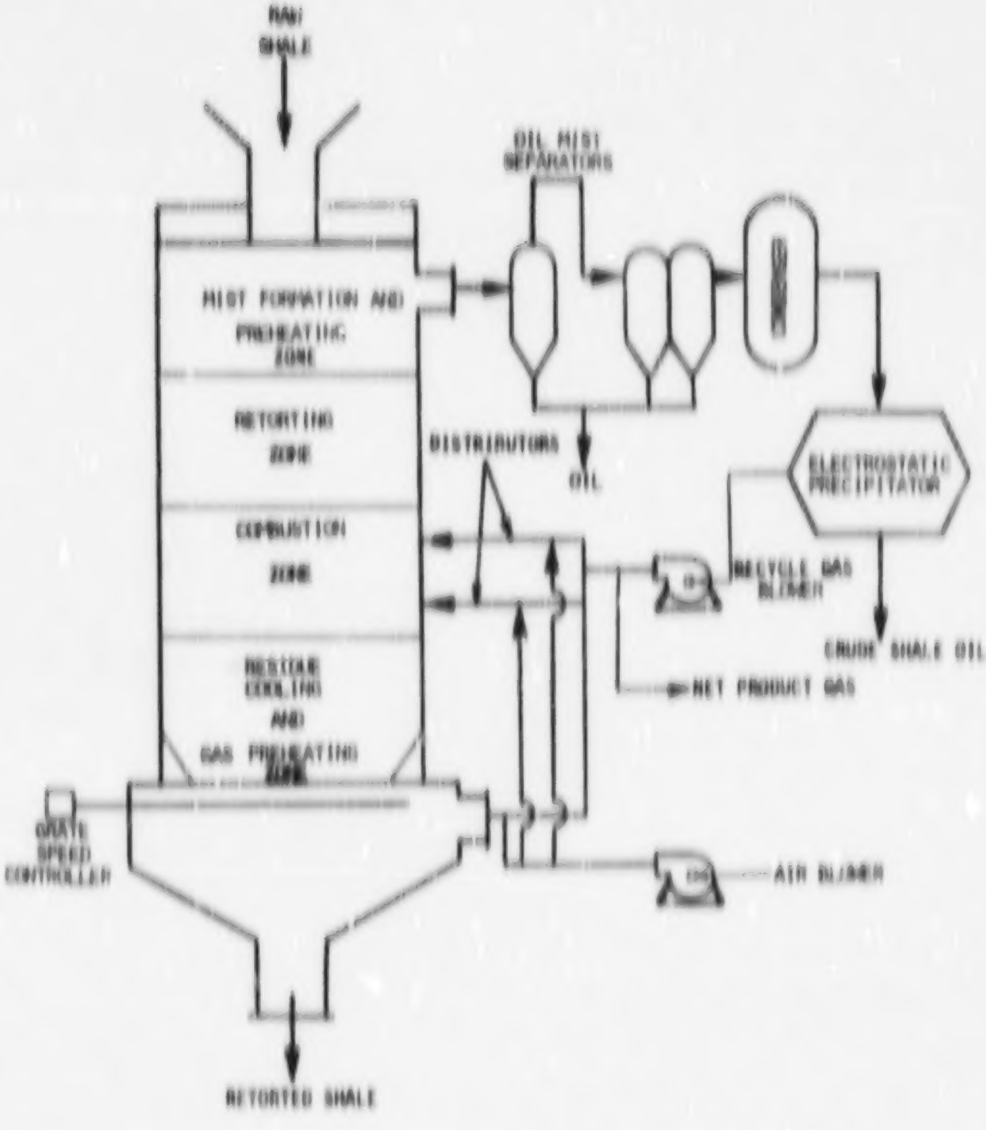

RAW SHALE
OIL MIST SEPARATORS
MIST FORMATION AND PREHEATING ZONE
RETORTING ZONE
DISTRIBUTORS
OIL
ELECTROSTATIC PRECIPITATOR
COMBUSTION ZONE
RECYCLE GAS BLOWER
CRUDE SHALE OIL
RESIDUE COOLING AND GAS PREHEATING ZONE
NET PRODUCT GAS
GRATE SPEED CONTROLLER
AIR BLOWER
RETORTED SHALE

FIGURE 2-12 SCHEMATIC OF PARAHO DIRECT MODE (GAS COMBUSTION RETORTING PROCESS (18)

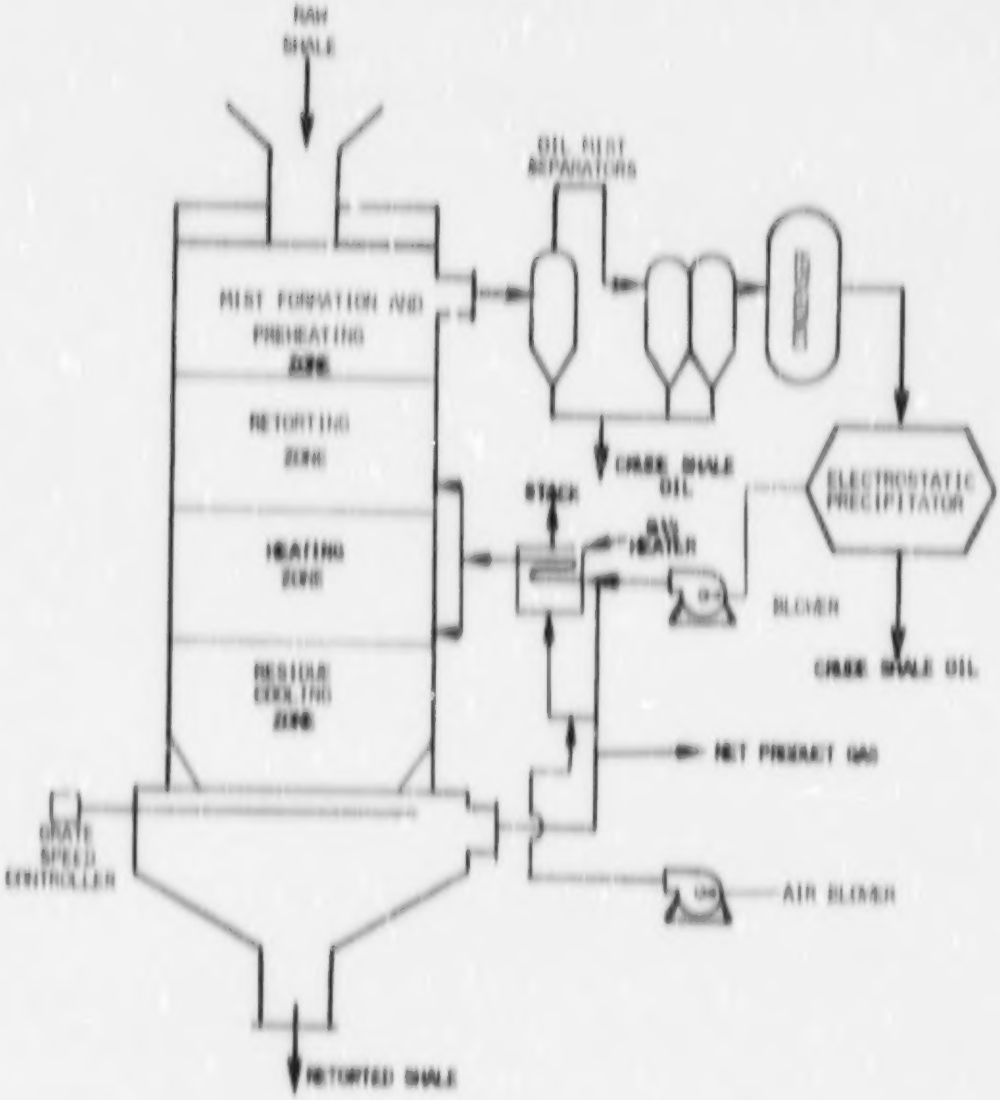

RAW SHALE
OIL MIST SEPARATORS
MIST FORMATION AND PREHEATING ZONE
RETORTING ZONE
HEATING ZONE
RESIDUE COOLING ZONE
CRUDE SHALE OIL
STACK
GAS HEATER
ELECTROSTATIC PRECIPITATOR
BLOWER
CRUDE SHALE OIL
NET PRODUCT GAS
GRATE SPEED CONTROLLER
AIR BLOWER
RETORTED SHALE

FIGURE 2-13 SCHEMATIC OF PARAHO INDIRECT MODE (HOT INERT GAS) RETORTING (10)

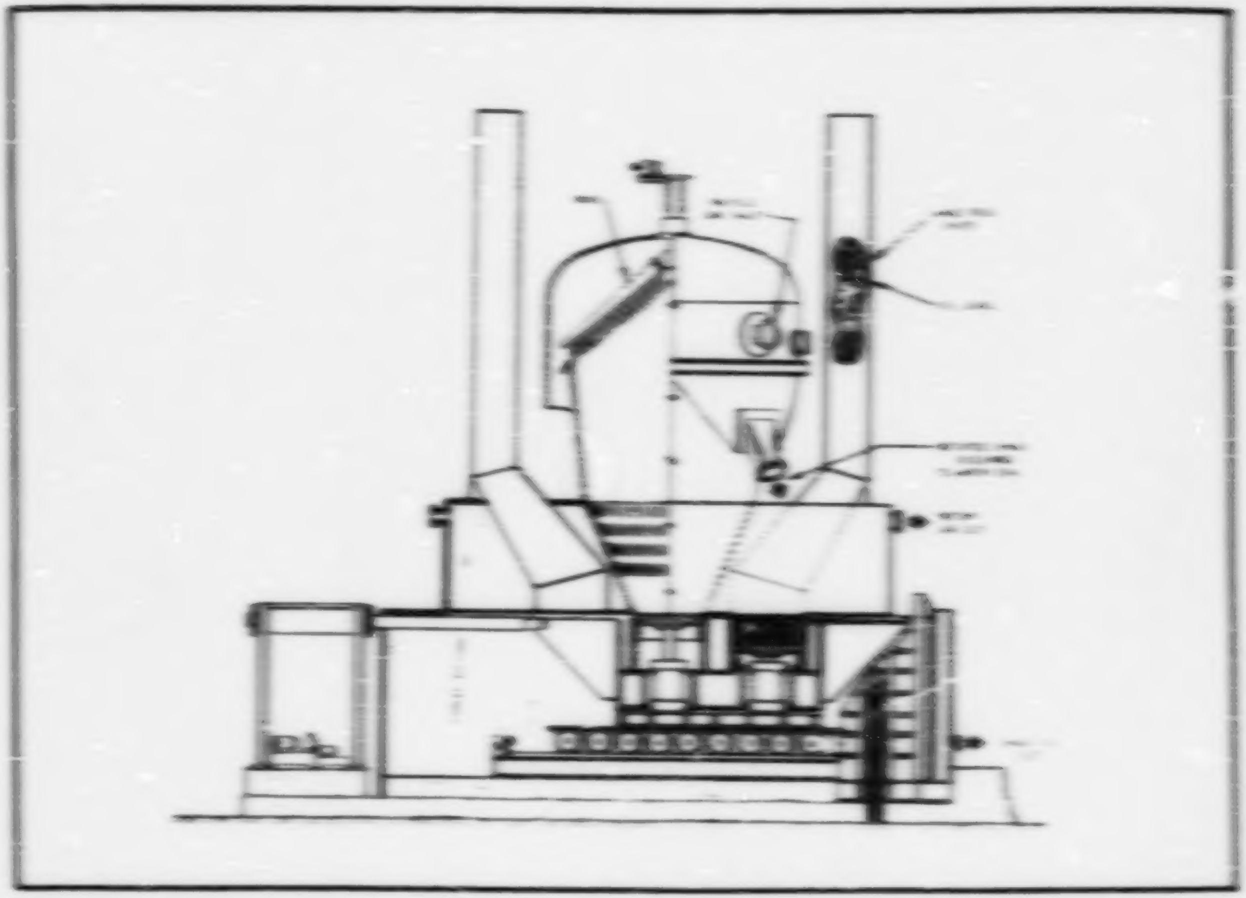


Figure 2-14. Side View of Union B Retort [36]

Primary crushing down to minus 25 cm (10 inch) will be carried out in the mine, and the raw shale will be fed to a conveyor for transport to the retorting site. After secondary crushing to approximately minus 8 cm (3 inch) the oil shale will be fed to the top of the modular retort. The full-size Paraho retort will operate in the same manner as the present demonstration pilot and semi-works retorts. The full-size retort (13 meters, 42-foot diameter and 30 meter, 104 foot high vessel) is expected to have a maximum capacity of approximately 11,800 tonnes/day (13,000 tons/day).

Water requirements are to be met by expanding the current facilities, which include a supply line from the Colorado River, and a small reservoir on the mesa itself. The present Public Service Co. of Colorado utility line will be increased in capacity to meet the anticipated 9000 KVA power needs. It is estimated that a project period of 3 to 4 years will be required to construct the facilities and demonstrate the retorting process.

The cost of the modular project was calculated in early 1975 to be $76 million (in 1975 dollars). The present work force of 50 would be expanded to approximately 300. A temporary construction and mine development crew of 400 to 450 people for about 18 months is anticipated.

The original funds for the Paraho program were nearly exhausted in April 1976, and the Anvil Point facilities were partially closed down. The Navy is currently negotiating a contract with DEI to produce 16,000 m^3 (100,000 bbls) of shale oil by 1978 for refining and military testing. The Paraho project thus has a temporary reprieve. Paraho submitted a request for ERDA funding of a 50,000 bbl/day demonstration plant at Anvil Points in 1975, but the request is awaiting congressional action on synthetic fuels legislation.

Commercial Use of Paraho Technology: Gulf and Standard of Indiana (Lease Tract C-a) are participants in the Paraho project and intend to use the process for part of the shale at Tract C-a (20). SOHIO, Sun and Phillips also plan to use the technology at the Utah lease tracts U-a and U-b except for retorting fines (21). Development plans at the lease tracts are reviewed in Section 2.4.

Environmental Programs: No extensive environmental studies have as yet been conducted on the Paraho process, pending further work on the process technology studies now in progress. Some initial emission and effluent measurements have been conducted by Paraho and by TRW/DRI (under current EPA contract). The results are to be published by EPA in 1977.

Emission control technologies for the Paraho processes have not as yet been indicated, since the basic technology is still under development. (Several retorted shale disposal methods are under investigation).

Retort gases and condensate waters are presently sent to a thermal oxidizer for incineration/evaporation. It is expected that pollution controls will be more fully delineated, together with the emissions and effluents involved, as further research proceeds during the next 18-24 months.

A Draft Environmental Impact Assessment statement was prepared by the U.S. Bureau of Mines in May 1975. Late in 1975, however, it was determined by ERDA that a new, full Environmental Impact Statement would be required. Its preparation and approval may take an additional 9 to 13 months from the present date.

2.2.3 The Union Oil Process (Retort B - Hot Inert Gas Retorting)

History of Technology Development (14,17): The Union Oil Company has been involved in oil shale activities for several decades, beginning in the 1920's with the purchase of 12,000 hectares (30,000 acres) of fee property containing oil shale resources. The development of Union's oil shale retorting technology was initiated in the early 1940's, and three variations of a vertical kiln retorting process, with upward flow of shale and counter-current downward flow of gases and liquids, have been developed. These variations are known as the Retort A, the Retort B, and the Steam Gas Recirculation (SGR) processes. The first concept, the Retort A process, has been carried through 1.81 tonnes (2 tons) per day and 45.5 tonnes (50 tons) per day pilot plants. This was followed by the construction and operation of a large demonstration plant in the late 1950's. The demonstration plant was designed for 317.5 tonnes (350 tons) per day capacity, but long-term operability was demonstrated at rates of 635 to 907 tonnes (700 to 1,000 tons) per day, with a peak rate of 1,089 tonnes (1,200 tons) per day. Although the demonstration of the Retort A process was extensive and successful, the Union Oil work, except for a continuing low level research effort, was suspended because of a plentiful supply of low-cost Middle East oil and natural gas at the time. The two improved versions of the Union Oil process, the Retort B and the SGR processes, were both developed in the 1970's in response to increasing energy demands and shortage of fuel supplies. Both the Retort B and the SGR processes have been carried through pilot plant stage. It is the Retort B process that Union Oil now proposes to construct and demonstrate at the 9,072 tonnes (10,000 tons) per day rate, along with all necessary auxiliary facilities. The SGR technology may be employed at later stage of development.

Process Technology Summary (17,22,36): In the Retort B process, shown in Figs. 2-14 and 2-15, crushed oil shale in the size range of 3 to 5 cm (1/8 to 2 inches) flows through two feed chutes to a solids pump. The solids pump consists of two piston and cylinder assemblies which alternately feed shale to the retort; the pump is mounted on a movable carriage and is completely enclosed within the feeder housing and immersed in oil. As shale is moved upward through the retort by the upstroke of the piston, it is met by a stream of 510 to 538°C (950 to 1000°F) recycle gas from the recycle gas heater flowing downward. The rising oil shale bed is heated to retorting temperature by countercurrent contact with the hot recycle gas, resulting in the evolution of shale oil vapor and make gas. This mixture of shale oil vapor and make gas is forced downward by the recycle gas, and cooled by contact with the cold incoming shale in the lower section of the retort cone. In the disengaging section surrounding the lower cone, the liquid level is controlled by withdrawing the oil product, and the recycle and make gas is removed from the space above the liquid level. As shown in Fig. 2-15, the make gas is first sent to a Venturi scrubber for cooling and heavy

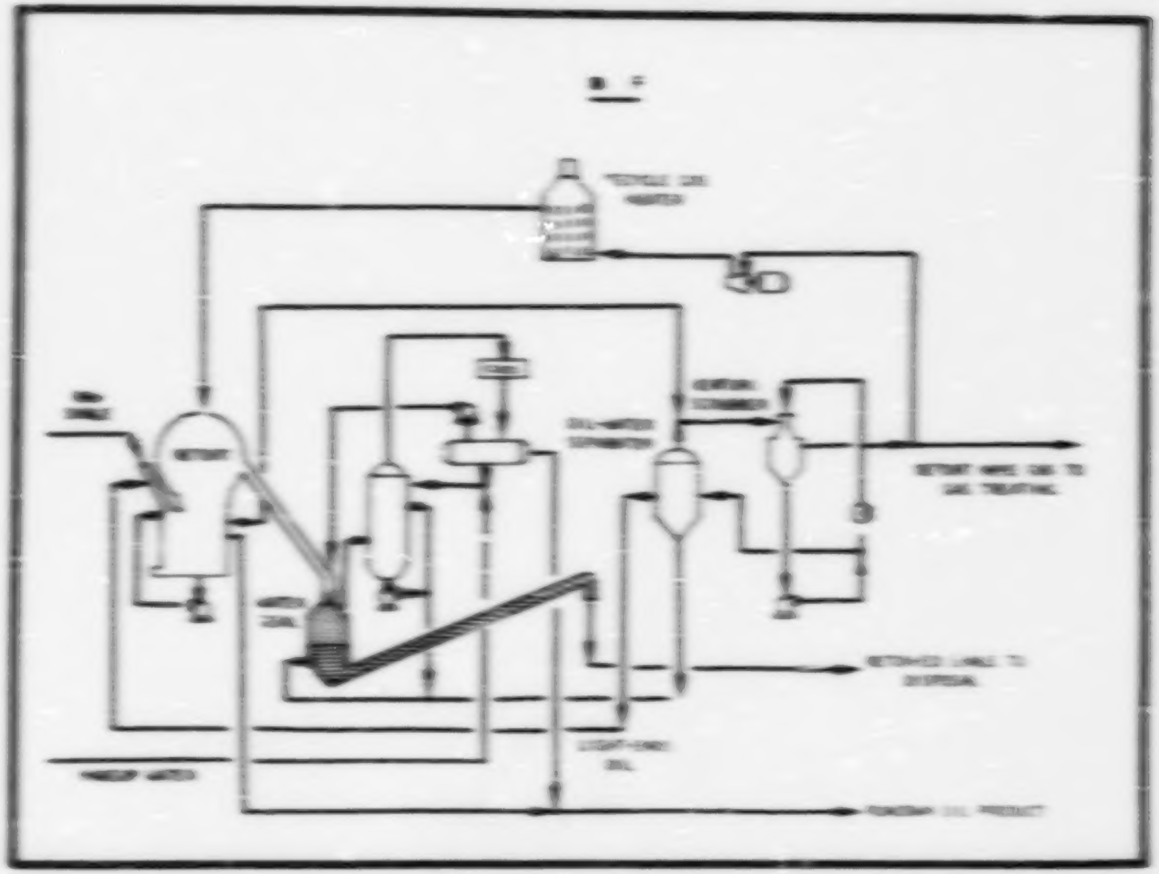

RETORT
RECYCLE GAS HEATER
OIL-WATER SEPARATOR
RETORT MAKE GAS TO GAS TREATING
RETORTED SHALE TO DISPOSAL
LIGHT-ENDS OIL

Figure 2-15. Flow Diagram for Union B Retorting Process (36)

ends removed by oil scrubbing. That portion of the 7100 kcal/m^3 (800 Btu/SCF) gas not recycled is then processed by compression and oil scrubbing to remove additional naphtha and heavy ends, followed by hydrogen sulfide removal in a Stretford unit. The sweetened make gas is used as plant fuel.

The product oil withdrawn from the retort is treated sequentially for solids, arsenic, and light ends naphtha removal. The solids removal is accomplished by two stages of water washing. The shale fines are collected in the water phase which is recycled to the water seal. The water seal is a Union Oil concept shown in Figure 2-15, in which a water level is maintained in a conveyor system for retorted shale removal to seal the retort pressure from atmosphere. For arsenic removal, a proprietary Union Oil process employing an adsorbent is utilized to reduce the arsenic content of the raw shale oil from 50 ppm to 2 ppm. The dearsenated shale oil is then sent to a stripping column for stabilization prior to shipment. The resulting crude shale oil has a 22.7° API gravity, 60°F pour point, 1.7% nitrogen and 0.81% sulfur content, and low (1.75%) Conradson carbon residue. At the present time, Union Oil does not envision additional upgrading of the crude shale oil onsite.

For the Retort B process, all the plant fuel requirements will be met by the make gas produced. The principal pollution control devices in the Union Oil design include the Stretford process for hydrogen sulfide removal from the retort make gas and oil/water separation and sour water stripping for waste water treatment. The treated waste water is used in the cooling and moistening of the retorted shale to provide for dust control and proper compaction.

Development Plans (23): To further the development of the Retort B process, Union Oil has proposed to the U.S. Energy Research and Development Administration a cooperative $120 million venture to build a 9,070 tonnes (10,000 tons) per day prototype plant capable of producing 1,240 m^3 (7,800 barrels) of shale oil per day. This prototype plant will be constructed on Union Oil property located on Parachute Creek, north of Grand Valley, Colorado. Union Oil owns a total of more than 12,000 hectares (30,000 acres) of fee property containing about 0.32 billion m^3 (2 billion barrels) of recoverable shale oil in the rich Mahogany zone.

The mining and the processing area for the demonstration plant will be located on a bench on the north side of the East Fork of Parachute Creek. The mine portal is designed to open on to a bench at the 2,100 m (7,000 ft) elevation. The conventional room and pillar method will be employed for production mining, with rooms 18.3 m (60 feet) high by 18.3 m (60 ft) wide and pillars having an 18.3 m (60 ft) square horizontal section. For the 9,070 tonnes per day prototype plant, the water consumption rate is estimated to be 81 m^3/hr (355 gpm) and the power requirement to be 11,300 kw. Union Oil filed water right applications as early as 1959, and a conditional decree has been awarded by the Colorado State Court to Union Oil for claimed water rights of 200 m^3/sec (118.5 ft^3/sec or 85,770 acre-feet per year).

All electric power will be purchased from outside the plant and probably be supplied by the Public Service Company of Colorado.

For the prototype plant, 7,620 tonnes (8380 tons) per day (dry basis) of retorted shale containing approximately 20 percent water will be transported to a disposal area in the East Parachute Creek Canyon, where it will be deposited in windrows proceeding up the south embankment. (See Figure 4-5).

Union Oil has estimated that 32 months will be required to design and construct the prototype plant with all its auxiliary facilities. The operating program to assess the technical, economical and environmental feasibility of the Retort B process is scheduled for two years. If the process proves to be viable, two more retorts would be constructed at the prototype site, bringing the total plant capacity to 27,200 tonnes (30,000 tons) of oil shale feedrate per day.

Environmental Programs: Union has conducted studies of the various environmental impacts to be encountered in a Retort B Prototype Plant. Among the control technologies to be employed are the following:

- Primary and secondary crushing will be done underground. A dust suppression system will be used for dusts from both mining and crushing operations.

- Because of the oil seals and water quench used, the retort is essentially free of particulate emissions. The plant is totally water consumptive. Any process waters or run-off will be captured in the plant's collecting pond.

- It is not planned to flare excess make-gas, but rather to absorb heavy ends into the oil product.

- Retorted, wet spent shale (20% H_2O) will be conveyed to windrows at the disposal site, and compacted to 1764 Kg/m^3 (90 lbs/ft^3) density for stability. Outer slopes and the top of the piles will be revegetated. A leachate ditch will be constructed to gather leachates from run-off, and discharge these to the plant water supply pond.

Union Oil is in the process of completing the environmental impact analysis (EIA). Originally scheduled to be issued in May 1976, release of the EIA has now been postponed indefinitely pending the outcome of synthetic fuels commercialization legislation and ERDA's decision to participate in the demonstration of the Union Retort B process at the 9,072 tonnes per day capacity.

2.2.4 Superior Oil Process (Hot Gas Retorting, Combustion of Residual Carbon) (24,25)

History: Superior Oil has owned some 2,600 hectares (6,500 acres) of oil shale land in the northern Piceance Creek Basin for nearly 40 years. In 1967 it began a drilling and geological evaluation program, and found that the deeper shales on the property contained attractive quantities of nahcolite ($NaHCO_3$) and dawsonite ($NaAl(OH)_2CO_3$) minerals, as well as oil shale. A research program was therefore initiated to permit integrated

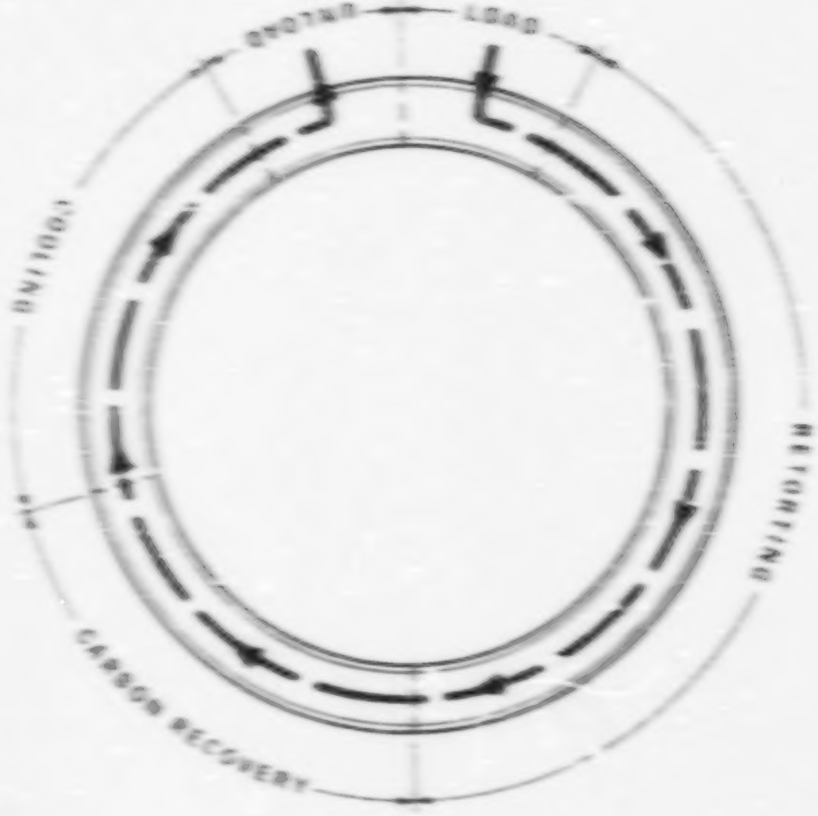

LOAD
UNLOAD
COOLING
RETORTING
CARBON RECOVERY

Figure 2-16. Top View of Superior Retort (25)

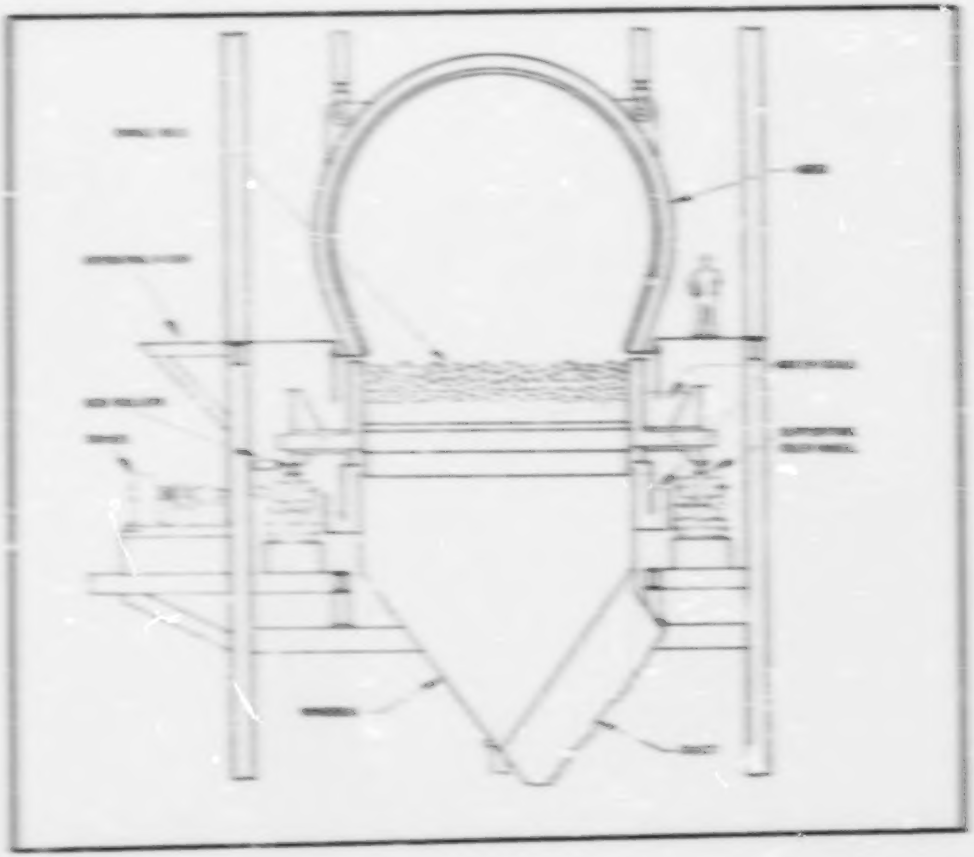


Figure 2-17. Cross Section View of the Superior Retort (Courtesy of Arthur McKee & Co.)

recovery of these minerals and shale oil. Included were investigations into the development of a circular grate retort.

A small laboratory unit is being tested in Superior's Denver, Colorado facilities. A pilot plant unit of 9-18 tonnes/hour (10-20 tons/hr) capacity is currently under construction in Cleveland, Ohio, to be in operation in the fall of 1976. If results are successful this will be followed by erection of a 18,000 tonnes/day (20,000 ton/day) full-scale commercial modular on Superior's Piceance Creek Basin site.

Meanwhile Superior has proposed to the Bureau of Land Management an exchange of 1,000 hectares (2,500 acres) of Superior land for 680 hectares (1700 acres) of adjacent federal land, in order to provide a more economically mineable tract with uniform geologic features. The U.S.G.S. has recently evaluated mineral values of the lands in question and has indicated that Superior's land has lower mineral values than the lands asked for in trade. A decision by the Bureau of Land Management on this land trade is still pending.

Process Technology: The Superior integrated process involves underground room and pillar mining at a depth of 600 meter (2000 feet); processed shale is to be returned to the underground mine for disposal. After primary crushing underground, 80-95% of the nahcolite present will be recovered mechanically by secondary crushing to minus 7.5 cm (3 in), and screening to remove the $NaHCO_3$.

The dawsonitic shale from $NaHCO_3$ recovery will be fed in 3 streams to a traveling circular grate retort (Figs. 2-16 and 2-17). A commercial sized module is expected to be 56 meters (185 ft) in diameter, with a capacity of 21,000 tonnes/day (23,000 tons/day). The doughnut-shaped retort has five separately-divided sections, through which the shale travels in sequence. These are a loading zone, retorting zone, residual carbon recovery zone, cooling zone, and unloading zone. Hot gases are drawn downward through the bed of shale on the grate, in the retorting zone, producing oil-laden vapors which are removed and the shale oil condensed. The oil-denuded and cooled gas stream is next recycled to the cooling zone, and drawn downward through the spent shale to reduce temperature of the shale prior to discharge. The cooled shale is fed to the leaching plant for recovery of alumina (Al_2O_3) and soda ash (Na_2CO_3).

During retorting the dawsonite in the retorted shale is converted to alumina and sodium carbonate. These are processed in the leaching plant by dissolution and subsequent recovery of soda ash ($NaHCO_3$) and aluminum hydroxide. The $Al(OH)_3$ is calcined to cell-grade alumina.

The spent shale (sodium-minerals and shale oil denuded) is sent to the underground mine as a wet cake on the production conveyor during its return run. No revegetation of retorted shale will therefore be required.

Development Plans: As noted previously a 9-18 tonne (10-20 ton) traveling grate pilot retort is to begin operation in Cleveland in the fall of 1976. If successful, this will be followed by construction of a full-scale

~18,000 tonnes/day (20,000 ton/day) modular plant and mine on Superior's 2,600 hectare (6,500 acre) property in Colorado's northern Piceance Creek Basin. This scale-up is partially dependent on a proposed land exchange with the federal government (24).

Water requirements for the full-scale plant are to be satisfied by utilizing the saline water in the "leached zone" aquifer directly above the proposed mine. Plant cooling waters will be returned to the aquifer. Power requirements for mining and processing will be purchased off-site. The cost of the full-scale plant and its manpower requirements have not been estimated.

Environmental Programs: Superior has not released detailed data on the emissions and effluents to be expected from its process. (Superior has indicated that a portion of the nahcolite produced could be added to the retort feed "for sulfur removal.") It can be expected that, in addition to control of normal shale oil plant emissions and effluents, control of brines and wastes from the leaching plant and associated mineral recovery activities will be necessary.

Superior is currently preparing an Environmental Impact Analysis of its integrated process, but no release date has as yet been established.

2.2.5 Lurgi-Ruhrgas Process (Recycled Hot Solids) (17,26,27)

History: This process was developed jointly by two German firms, Lurgi-Gesellschaft and A. G. Ruhrgas, in the 1950's for low-temperature coal carbonization and for cracking saturated hydrocarbons to olefins. Two lignite carbonization units with a combined plant capacity of 1500 tonne/day (1700 tons/day) began operation in Yugoslavia in 1963. A small 14-23 tonne/day (16-25 ton/day) plant in West Germany has been used to retort Colorado oil shale, at a yield of 100 percent of Fischer assay. The Lurgi Company indicates that a retorting unit of 5000 tonnes/day is technically feasible.

Process Technology: In the L-R process, minus 1.3 cm (1/2 in) shale is heated by contact with hot, finely-divided solids in a horizontal, cylindrical vessel with a screw conveyor. The finely-divided heat carrier may be sand or coarse shale ash. The products are withdrawn from the top of the mixer, dedusted, and condensed. The spent shale and heat carrier pass into a lift line, together with dust from dedusting. Air is added and the carbon is burned off the spent shale-heat carrier mixture. Thus the carrier is reheated and is recycled after dust removal.

Because of the direct contact between shale solids and heat carrier, heat transfer is rapid, leading to high-throughput retorts. Care must be taken to avoid readsorption of shale-oil vapors on the solids in order to prevent loss of yield. Patents cover related processes developed by a number of U.S. companies which have examined this potentially attractive retorting method.

Development Plans (28): In late 1975 American Lurgi presented a proposal to 14 major owners or leasees of oil shale land to elicit support for construction of a 4,000 tonne/day demonstration plant of the L-R process. It was estimated in the proposal that the plant could be operational 36 months after project approval. This proposal is apparently still active, but no actual site is indicated at present.

Environmental Studies: No specific environmental studies have been published on the L-R process to date, although limited data are available regarding certain emissions and effluents from the process in pilot scale.

2.3 COMMERCIAL DEVELOPMENT PLANS EMPLOYING IN-SITU TECHNOLOGY

In-situ extraction of shale oil has attracted research interest for many years. Only recently, however, has commercial interest emerged. Both "true" and "modified" in-situ projects are included in the commercial projects discussed below. The major emphasis in this section is placed on the Occidental process since it is the most nearly commercial of the in-situ developments.

2.3.1 The Occidental Modified In-Situ Process (29,30,31,32)

History of Technology Development: Occidental Petroleum Corporation's involvement in oil shale technology is a relatively recent development. In late 1972, Garrett Research and Development Company (now Occidental Research and Development), a subsidiary of Occidental Petroleum Corporation, announced plans for the field testing of a modified in-situ shale oil recovery scheme which is the subject of U.S. Patent 3,661,423. The actual work began in the summer of 1972 on the private property (known as the D. A. Shale, Inc. property) at the head of Logan Wash outside of Debeque, Colorado. In the ensuing months, three research retorts, each 9.1 m (30 ft) on a side and 21.9 m (72 ft) high, were prepared and ignited.

At the end of 1974, the project was transferred to an operating branch of the company, when Occidental Oil Shale, Inc., a subsidiary of the Occidental Oil and Gas Production Division, was created. Concurrently, a decision was made to initiate the development of a commercial size retort in the commercial mine, located off the north side of Logan Wash about a quarter mile below the head of a canyon. The commercial mine is being developed at a new location because there is insufficient room at the head of Logan Wash (the research mine location) to permit a large mining operation, and because the research mine is located just below the Mahogany Ledge and too high for the construction of commercial size retort columns. The first commercial size retort (Retort No. 4), with a 36.6 m (120 ft) by 36.6 m (120 ft) cross section and 76.2 m (250 ft) height and containing 15 gpt rubblized shale, was ignited from the top on December 10, 1975. A total of 4,300 m^3 (27,000 bbls) of oil has been recovered from the retort, and production rates of about 80 m^3 (500 bbls) per day have been realized.

Process Technology Summary: The modified in-situ process for shale oil recovery consists of retorting a rubblized column of broken shale, formed by expansion of the oil shale into a previously mined out void volume. The Occidental process involves three basic steps. The first step is the mining out of approximately 20% of the oil shale deposits (preferably low grade shale or barren rock), either at the upper and/or lower level of the shale layer. This is followed by the drilling of vertical longholes from the mined-out room into the shale layer, loading those holes with an ammonium nitrate-fuel oil (ANFO) explosive, and detonating it with appropriate time delays so that the broken shale will fill both the volume of the room and the volume of the shale column before blasting. Finally, connections are made to both the top and bottom and retorting is carried out (Fig.2-18).

Retorting is initiated by heating the top of the rubblized shale column with the flame formed from compressed air and an external heat source, such as propane or natural gas. After several hours, the external heat source is turned off, and the compressed air flow is maintained, utilizing the carbonaceous residue in the retorted shale as fuel to sustain combustion. In this vertical retorting process, the hot gases from the combustion zone move downwards to pyrolyze the kerogen in the shale below that zone, producing gases, water vapor, and shale oil mist which collects in the trenches at the bottom of the rubblized column (Fig. 2-19). The crude shale oil and byproduct water are collected in a sump and pumped to storage.

The off-gas consists of products from shale pyrolysis, carbon dioxide and water vapor from the combustion of carbonaceous residue, and carbon dioxide from the decomposition of inorganic carbonates (primarily dolomite and calcite). Part of this off-gas is recirculated to control both the oxygen level in the incoming air and the retorting temperature. The off-gas has a heating value of approximately 580 kcal/m^3 (65 Btu/SCF), and the part of the off-gas not recycled is currently flared.

Occidental envisions using the low Btu gas from a commercial retort for generating electric power. Turbines manufactured by Brown-Boveri of Switzerland will be investigated for this application. According to Occidental's estimate, only 20 to 25 percent of the electric power produced from the low-Btu gas is required for operating the modified in-situ process.

Occidental has not disclosed any information on the design of surface oil and gas treatment plants. The minimum treatment required for the crude shale oil produced from the retorting process will include phase separation of the oil from the byproduct water and the stabilization of the oil product. The waste-water effluent from the phase separator may be used for steam generation after appropriate treatment.

Retort water volume produced from the Occidental process is approximately equal to shale oil volume. This quantity of water is approximately equal to in-situ shale processing requirements. It is not known whether Occidental has investigated the treatment of the retort water for use in oil shale development.

The crude shale oil produced from the Occidental process has a specific gravity of 0.904 (API gravity of 25°), a pour point of 21°C (70°F), a sulfur content of 0.71 weight percent and a nitrogen content of 1.50 weight percent. The crude shale oil is also reportedly free of solids and may be potentially usable as boiler fuel without upgrading.

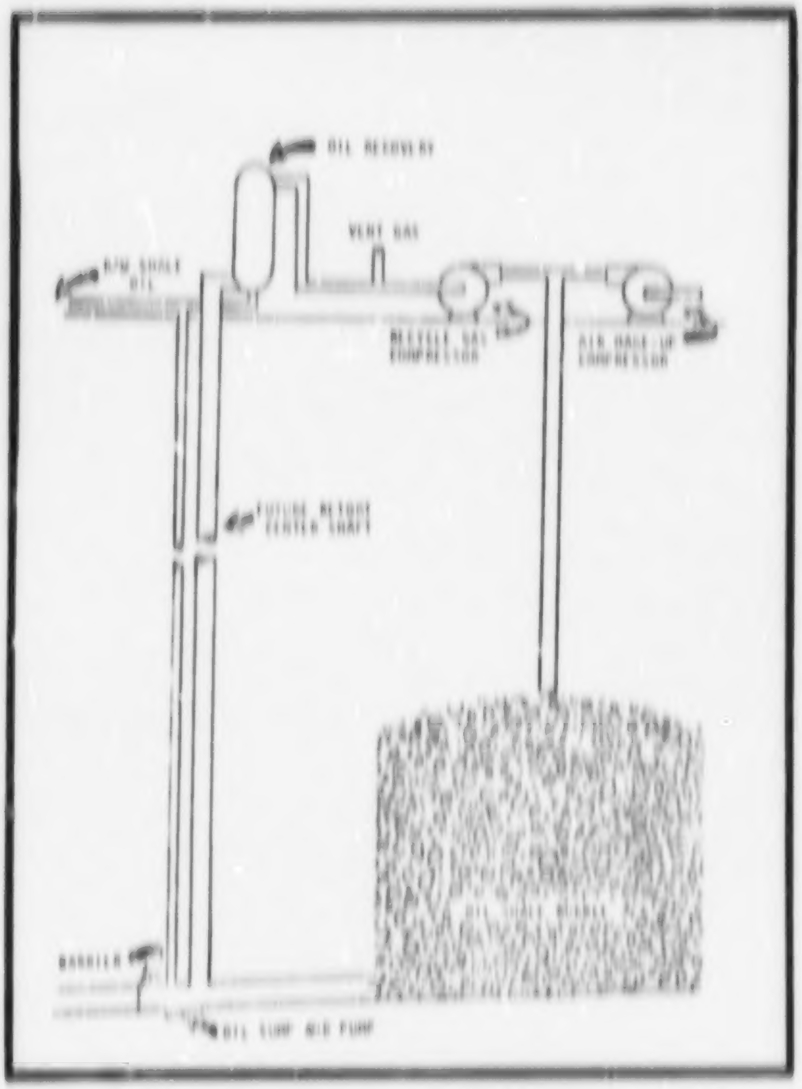

OIL RECOVERY
VENT GAS
RAW SHALE OIL
RECYCLE GAS COMPRESSOR
AIR MAKE-UP COMPRESSOR
FUTURE RETORT CENTER SHAFT
BARRIER
OIL SUMP AND PUMP

Figure 2-18. Schematic of the Occidental Modified In-Situ Process (30)

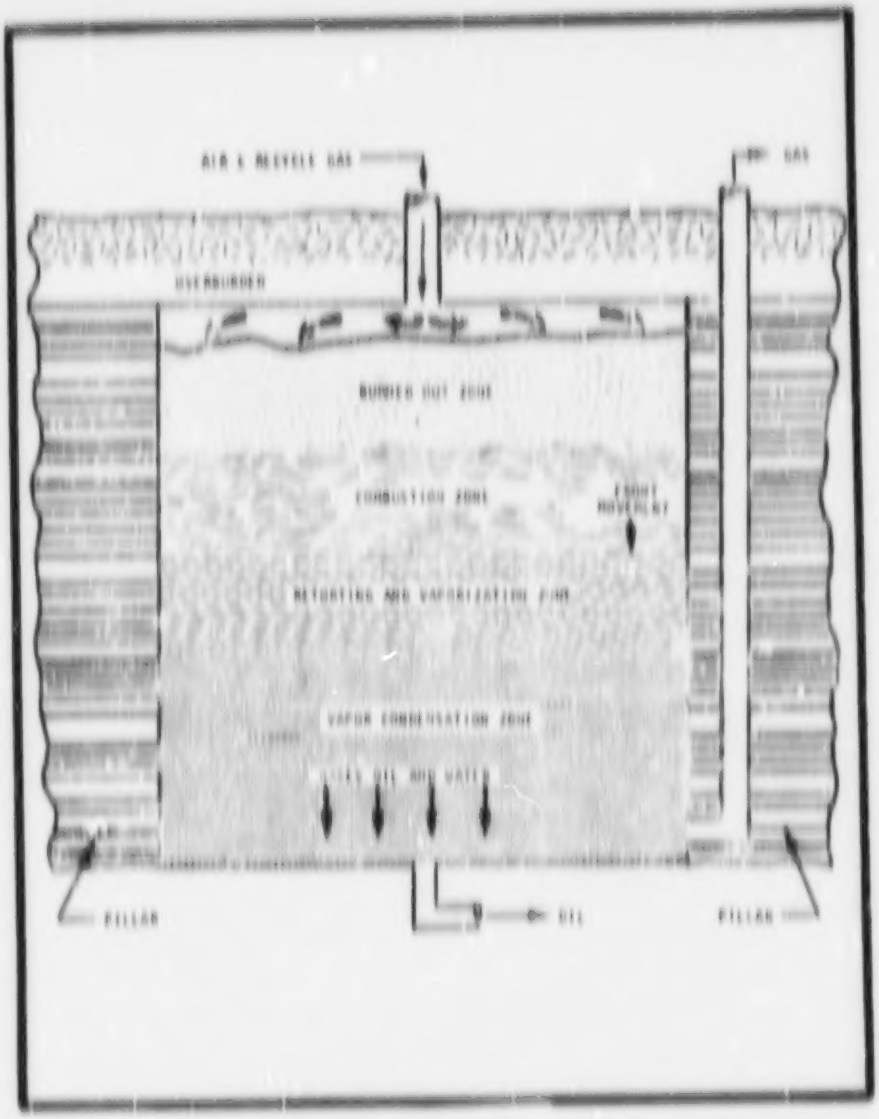

AIR & RECYCLE GAS
GAS
OVERBURDEN
BURNED OUT ZONE
COMBUSTION ZONE
FRONT MOVEMENT
RETORTING AND VAPORIZATION ZONE
VAPOR CONDENSATION ZONE
OIL AND WATER
PILLAR
OIL
PILLAR

Figure 2-19. Flame Front Movement in the Occidental Modified In-Situ Process (30)

Development Plans: Occidental has invested over $30 million during the last five years in the development of the modified in-situ process. A second commercial size retort (Retort No. 5), similar in dimensions to Retort No. 4, is now being prepared. If the process proves to be successful at the current 79.5 m^3/day (500 bbl/day) level, Occidental expects to attract sufficient support for the construction of a 795 m^3/day (5,000 BPD) demonstration mine and retort. The demonstration mine and retort would provide the necessary information on the technical and economic feasibility and the environmental acceptability of advanced mining techniques and multiple in-situ retorts. After the successful demonstration of these concepts, Occidental plans to expand the shale oil operations to commercial proportions, without the need for federal subsidies or loan guarantees.

The Occidental in-situ experiments have been conducted on private land controlled by D. A. Shale, Inc., through a three-year lease and option agreement that has since been extended. The D. A. Shale property contains relatively low grade shale (15 gpt) and may be marginal for commercial operation. Occidental is seeking to enlarge its holdings of land underlain by higher grade oil shale and has nominated two tracts in Colorado under the Interior Department's Prototype Oil Shale Leasing Program (Section 2.4).

Environmental Studies and Activities: During its in-situ experiments, Occidental has contracted Claremont Engineering to conduct ambient monitoring of gaseous criteria pollutants and stack monitoring of selected pollutants in the retort off-gas, such as SO_2, CO and H_2S. The daily averages of the measured values of the pollutants have been reported to the State of Colorado on a quarterly basis. The retort off-gas is of special concern because of the large quantity of gas involved, which eventually must be vented to the atmosphere after burning (either in turbines to generate electric power or through simple incineration).

A water problem of special concern is the contamination of naturally occurring groundwater infiltrating the underground development of an oil shale zone. At Occidental's present site, there is little or no ground water (pump tests have yielded less than 2.3 m^3/hr or 10 gpm) due to the geology of the area. According to Occidental, the mining scheme for the center of Piceance basin should be so designed to keep the aquifers isolated from the target oil shale below. In this area, the access shaft to the oil shale zone should also be lined (e.g., with cement) to prevent contamination of the aquifer. In areas where there is saline water below and within the target oil shale zone, Occidental believes that in most cases, it is possible to either seal off the area or to pump the water to the surface and reinject i in the same formation downdip. A closely related area of concern, the potenti for underground leaching of the spent shale, is also not considered by Occidental to be a significant problem. Occidental envisions that leaching of the spent shale will be limited due to the large size of the shale pieces. The movement of the water will be slow and probably confined to the spent chimneys The water quality in Roan Creek, Logan Wash and Dry Gulch is currently monitored by Occidental.

There is no retorted or spent shale disposal problem associated with the Occidental process. The rock mined is not significantly different from the naturally occurring material in the region and will be dumped into the canyons near the oil shale mine. A permit for increasing the size of its mined waste disposal pile from 382,000 m^3 (500,000 cubic yards) to 6,500,000 m^3 (8.5 million cubic yards) was recently granted to Occidental by Garfield County Commissioners on January 13, 1976. The approval of this special permit provides Occidental with sufficient mined rock (low grade shale) disposal capacity to expand into the large demonstration phase. The permit was granted on the basis that the raw shale pile would not be found to degrade the water quality of the area. A second stipulation of the permit is that upon completion of the raw shale pile, Occidental will restore the vegetative cover to a condition compatible with comparable natural talus slopes in the vicinity.

Occidental has developed a list of 48 activities for which environmental effects and permits must be considered, and has assembled a team of seven people to gather environmental baseline data. The studies conducted include a meteorological study, fauna and flora studies, the completed paleontological and archaeological studies, ambient air and retort vent gas monitoring studies, water quality monitoring studies, and others. The EIA for the development of the Occidental process is scheduled to be released in December 1976.

2.3.2 Western Oil Shale Corporation (WESTCO) (16)

Western Oil Shale Corporation (WESTCO) initiated a project in 1975, with a consortium of 10 companies, to design a modified in-situ project on a site in the Uinta Basin. Three underground vertical retorts ("chimneys") are to be investigated, using special DuPont explosives.

2.3.3 Geokinetics, Inc. (16)

Geokinetics has also begun field tests of its "true" in-situ process on a site some 15 miles south of federal lease tracts U-a/U-b. After explosive fracturing, a horizontal fire flood is to be employed.

2.3.4 ERDA In-Situ Research, Development and Demonstration Project

ERDA has issued a Program Opportunity Notice for in-situ proposals from private interests. Federal support is indicated through commercial demonstration. ERDA is currently negotiating contracts with Occidental, Equity, Geokinetics, and Talley-Frac.

2.4 FEDERAL OIL SHALE LEASE TRACTS

Late in 1973 the Department of the Interior prepared six oil shale prototype lease offerings on federal land in Colorado, Utah and Wyoming (33). Table 2-1 summarizes the high bids received for the offered tracts (34). Recently requests for in-situ nominations have been solicited, since no bids were received for the Wyoming tracts in 1973. The locations of the four active leases and the four preferred in-situ nominations are shown in Figures 2-1 and 2-2 (35).

Table 2-1. Results of Federal Oil Shale Lease Offerings (34)

Tract	Area (Hectares) (Acres)	Recoverable Resource Estimate $10^6 m^3$ (10^6 bbls)	High Bonus Bid (10^6 $)	Original Lessee(s)
Colorado				
C-a	2060 (5088)	200 (1300)	210	(Rio Blanco Oil Shale Project Standard of Indiana Gulf Oil Corp.)
C-b	2062 (5093)	116 (723)	118	(Atlantic Richfield Ashland Oil Shell Oil The Oil Shale Corp.; TOSCO)
Utah				
U-a	2073 (5120)	53 (331)	76	Sun Oil Co/Phillips
U-b	2073 (5120)	43 (271)	54	White River Shale Oil Corp. (Sun, Phillips, Sohio)
Wyoming				
W-a	2070 (5113)	57 (354)	None	-
W-b	2070 (5113)	57 (352)	None	-

The status of development plans at the federal lease tracts is reviewed in this section. The developers of tracts C-a, C-b and U-a/U-b have submitted detailed development plans to the area oil shale supervisor. The in-situ nominations have been made and final choice for leasing awaits an Environmental Impact Statement (EIS). In March of 1976 Roxana (Tract C-b) formally requested a suspension of tract development requirements and a postponement of the 4th and 5th bonus payments as required by the lease. RBOSP (Tract C-a) and WRSP (Tracts U-a/U-b) have submitted similar suspension requests to the Department of the Interior in July of 1976. Although the area oil shale supervisor (AOSS) is currently reviewing the Detailed Development Plans for each tract, the Secretary of the Interior granted the suspension of development at C-a and C-b in August 1976, and at U-a/U-b in October 1976.

2.4.1 Tract C-a - Rio Blanco Oil Shale Project (RBOSP) (7)

Project Description: The Rio Blanco Oil Shale Project (Standard of Indiana and Gulf Oil Corp.) has recently submitted a detailed development plan (DDP) to the area oil shale supervisor (AOSS) in Grand Junction. This plan envisions a phased development of Tract C-a using open pit mining (Table 2-2). Mining will commence at the northwest corner of the lease tract and will have disturbed less than 300 hectares (750 acres) at the end of Phase I. Phase I will involve the construction and operation of two TOSCO II retorts, each capable of processing 9,700 tonnes (10,700 tons) of oil shale per day. During 1982, total crude shale oil production is planned at 1,400 m^3/day (9,000 bbls/day) (see Table 2-2). Phase I processing operations will include a thermal cracking plant and a sulfur recovery plant.

Phase I support systems include water supply from ground water sources on the tract (5.3-9 m^3/min or 1400-2400 GPM), a power line from an existing 230 KV line near the White River, and an extension of the existing Ryan Gulch-C-a road to Rangeley. Product oil will initially be pipelined to Rangeley, thence through an existing AMOCO pipeline to a refinery. Peak manpower requirements during Phase I is expected to be about 700 employees.

In addition to DDP approval by the AOSS, the Rio Blanco project requires several government actions before development can proceed. Plans call for location of processing facilities and the retorted shale disposal area outside the tract (to the north). An amendment to the Mineral Leasing Act of 1920 is apparently required to allow this use of off-tract federal lands, and such legislation is now pending in the U.S. Congress (S.2413 and H.11163). RBOSP also requires approval of rights-of-way for service corridors and State of Colorado support for the proposed Rangeley access road. Finally, RBOSP envisions its employees living primarily in Rangeley, and has assisted the town in planning for growth. Urban expansion will probably require access to surrounding federal land; a mechanism for acquiring such land will be required.

Phase II operations at C-a are envisioned to begin in 1985 and will employ both TOSCO and Paraho (gas combustion) retorting. Open pit mining will expand to about 108,000 tonnes/day (120,000 tons/day) to feed the retorts. Rio Blanco plans to upgrade crude shale oil at 8,960 m^3/day (56,000 bbls/day) by delayed coking, and by hydrogenation of naphtha and gas oil distillation fractions.

Table 2-2. Tract C-a - Rio Blanco Oil Shale Project Summary (7)

	PHASE I		PHASE II
	Stage 1	Stage 2	
MINING			
Type	Open Pit	Open Pit	Open Pit
Production	10,300 tonnes/day	19,400 tonnes/day	108,000 tonnes/day
Ore Haulage	Belt Conveyor	Belt Conveyor	Belt Conveyor
Overburden Haulage	Truck	Truck	Belt Conveyor
PROCESSING			
Retorting	TOSCO II	TOSCO II	Combination of TOSCO II & Gas Combustion/Paraho
Upgrading	Thermal Cracking	Thermal Cracking	Delayed Coking & Hydrotreating Belt Conveyor
PRODUCTS			
Pipelineable Shale Oil	720 m^3/day (4,500 BPSD)	1440 m^3/day (9,000 BPSD)	
Upgraded Shale Oil	-	-	8,830 m^3/day (55,000 BPSD)
Sulfur	11 tonnes/day	22 tonnes/day	153 tonnes/day
Ammonia (anhydrous)	-	-	270 tonnes/day
Coke	-	-	425 tonnes/day
Moisturized Processed Shale	13,000 tonnes/day	25,000 tonnes/day	107,700 tonnes/day
WATER DEMAND	1.7x10^6 m^3/yr (1,390 AFY)	3.5x10^6 m^3/yr (2,370 AFY)	12.3x10^6 m^3 (10,000 AFY)
POWER DEMAND	17.7 ●	28.8 ●	227 ●
PEAK EMPLOYMENT			
Construction	700	400	2,200
Operation	300	500	1,700
ELAPSED TIME			
Construction	2 years	2 years	3 years
Operation	3 years	3 years	20-30 years

Notes: BPSD = bbls per stream day
AFY = acre-feet per year
● = megawatts = 10^6 watts

Hydrogen will be produced on site by partial oxidation (gasification) of heavy shale oil distillation residue. The operation is designed to consume all gaseous products as plant fuel. Elemental sulfur and ammonia will be recovered as co-products from gaseous and liquid product streams.

Phase II operations are expected to be supplied by "on tract" ground and surface water. Expansion beyond 8,960 m^3/day (56,000 bbls/day) of shale oil will require additional water supplies and Rio Blanco has applied for an 8.5 m^3/sec (300 ft^3/sec) water right on the White River.

Environmental Programs: Mining and shale preparation air pollution control at Tract C-a will include frequent watering at the mine and on transport roads, enclosing and spraying raw and crushed shale at transfer points, and using baghouse filters with induced-draft fans for crushing and screening operations.

Process pollution control is to be accomplished by technology similar to that described in the TOSCO II section (2.2.1). Phase I operations will include a thermal oxidizer to handle certain ammonia and sulfur containing gas streams, excess fuel gas, and oil/water separator sludges.

Phase II air pollution control will include technology similar to that used in Phase I, with the combination of GCR and TOSCO II retorts supplying the operation with entirely gaseous fuels. Cleaned low and high Btu fuel gases generally present a lower emissions potential from process heaters than liquid fuels. Hydrogen sulfide and ammonia removal from in-plant fuels, the use of wet and dry venturi scrubbers, and incineration of trace hydrocarbons in the TOSCO II preheat system are the major air pollution control techniques.

Water quality control at Tract C-a is based on a zero discharge concept. Rio Blanco plans to collect storm and surface waters, mine waters, and process waters for in-plant use or for controlled evaporation. The ultimate disposition of wastewater is evaporation, or entrainment as a permanent component of retorted shale.

RBOSP plans to dispose of retorted shale, mine overburden, and other solid wastes (spent catalysts, coke, lime sludge, spent zeolites) on a site called "84 Mesa," north of Tract C-a. This site is sufficient to accommodate waste for up to 30 years before backfilling of the open pit is planned. Tests are currently underway to determine the best revegetation techniques for the soil and overburden profile which would eventually "cap" the retorted shale pile.

RBOSP is conducting a two-year baseline monitoring program to define natural conditions at Tract C-a prior to oil shale development (part of lease stipulations). Continued monitoring of meteorology, ambient air and water quality, ground and surface water hydrology, soils and geology, terrestrial and aquatic flora and fauna is planned through development stages of the project. A more detailed description and evaluation of monitoring activities at C-a and other lease tracts is presented in Chapter VI of this report.

2.4.2 Tract C-b (Roxana) (6)

Project Description: Tract C-b is a joint venture of Ashland Oil, Inc. and Shell Oil Company, known as the Roxana Shale Oil Company. Atlantic Richfield and The Oil Shale Corp. (TOSCO), originally partners in the C-b venture, have withdrawn from the project. Roxana's two remaining partners submitted a detailed development plan to the Area Oil Shale Supervisor (AOSS) in February 1976. The future of the project is uncertain however, due to ARCO and TOSCO withdrawal, technical and economic uncertainties about extraction of deep Mahogany Zone shale on the tract, and lack of a federal energy policy.

Table 2-3 summarizes the Roxana project plans. The C-b DDP envisions development mining (Phase I) for about 5 years in order to establish deep mining technology and define geologic and hydrologic conditions on the tract. Coarse ore would be stockpiled until completion of the Phase II construction of surface retorting and upgrading facilities. Roxana plans to use TOSCO II technology (both Ashland and Shell are members of the Colony Group), and surface operations are expected to be similar to those planned by Colony for use at the Parachute Creek property.

Water produced during Phases I and II may exceed project demand, and excess waters will be directly discharged if quality is adequate, and reinjected or used for spray irrigation if water is of poor quality. Phase III processing operations will likely require more water than can be obtained from aquifers on the tract, and Roxana plans to obtain additional water from the Colorado River (perhaps in conjunction with Colony development).

A product pipeline(s) will follow the water supply corridor south from the tract via Parachute Creek to the Colorado River. An electric power corridor will extend to the north and east to connect with the White River grid.

Environmental Programs: During the mine development and construction phases at C-b, air pollution sources will mainly be fugitive dust, stationary diesel emissions, and vehicular emissions. Dust control will be accomplished by watering, by use of chemicals, and by minimizing exposed soil surfaces.

Shale preparation and retorting process emissions and effluents, and associated pollution control technologies at C-b are the same as those described in Section 2.2.1 of this report (TOSCO II process). All process waste water will be consumed in the moisturizing of retorted shale.

Retorted shale and other solid wastes will be disposed of on the east side of Tract C-b in Sorgum Gulch (see Section 4.3). During Phase I, a dam will be constructed below Sorgum Gulch for collection and storage of excess mine water. Later, the dam will serve to retain any runoff from retorted shale piles. Colony's experience in revegetating spent shale at Parachute Creek will be applied at C-b. As was the case with RBOSP, Roxana is conducting a two-year baseline environmental monitoring program as required by lease conditions.

Table 2-3. Tract C-b - Roxana Oil Shale Project Summary [6]

	PHASE I	PHASE II	PHASE III
MINING			
Type	Mine Development (room & pillar)	Development Mining	Room and Pillar
Production	2.5 x 10⁶ total tonnes	Stockpiling of Ore	60,000 tonnes/day
Ore Haulage	To Storage via Belt Conveyor		Belt Conveyor
PROCESSING			
Retorting		Plant Construction	TOSCO II
Upgrading			Delayed coking, hydrotreating
Processed Shale Haulage			Conveyor
PRODUCTS Pipelineable Shale Oil Upgraded Shale Oil Sulfur Ammonia Coke Moisturized Processed Shale		Plant Construction	8000 m³/day (50,000 bbls/day) 175 tonnes/day 136 tonnes/day 227 tonnes/day 60,000 tonnes/day
WATER DEMAND	Excess Water Produced	Excess Water Produced	Total Requirement [illegible] (72.3 CFS)
POWER DEMAND	5-10 MW	20 MW	102 MW
PEAK EMPLOYMENT			
Construction	425	2000	1000-1200
Operation			
ELAPSED TIME			
Construction	5 years	4 years	20-30 years
Operation	1 year	1 year	

2.4.3 Tracts U-a/U-b - White River Shale Project (WRSP) (21)

Project Description

The lessees of Tract U-a (Phillips Petroleum, Sun Oil) and U-b (Phillips, Sun, Sohio) have proposed joint development of the two tracts, which adjoin one another. A Detailed Development Plan for the two tracts was submitted to the Area Oil Shale Supervisor (AOSS) in April 1976. Final DDP approval is still pending. In late 1976 WRSP requested a temporary suspension of operations and further lease payments on both tracts.

The project activities planned for the tracts are expected to occur in four phases, as summarized in Table 2-4. In Phase I a 335 meter (1100 ft) deep access shaft for a subsequent room-and-pillar mine will first be established near the center of the combined tracts, in order to permit testing of the shale deposit. Mining will be initiated some six months later. Mine development will continue, and extend throughout the following Phase II, with an expansion of production from 1814 tonnes (2000 tons) to 9100 tonnes (10,000 tons) of raw shale per day.

Phase II will be of 4 years duration, and will involve the construction and operation of a single modular vertical retort with a throughput capacity of up to 9100 tonnes of shale (10,000 tons) per day. The retort design has not yet been selected, but could be a Paraho direct-heat design later modified for indirect heating, or another available verticle-type retort. At a retort feed rate of 6800 tonnes (7500 tons) of coarse shale per day, some 750 cubic meters (4700 barrels) of crude oil would be produced daily.

A commercial plant (Phase III), with a first "train" projected capacity of 72,500 tonnes (80,000 tons) per day, will be constructed for start-up some 2½ years after the successful conclusion of Phase II. This will be followed by start-up of a second commercial train of the same capacity some 1½ years after the first, thus bringing total plant production capacity to an ultimate 145,000 tonnes (160,000 tons) per day.

It is currently intended that the major portion (85%) of the Phases III and IV retorting will be carried out in vertical, gas-combustion type, direct and indirect-mode retorts, but that the 15% of crushing fines produced will be pyrolyzed in TOSCO II-type retorts. It is expected that all of the 15,800 cubic meters (100,000 barrels) of shale oil produced daily at maximum scale-up will be upgraded in facilities similar to those to be used for the Colony and Tract C-b projects.

During Phases I and II water for the White River Shale Project will be obtained from a 146,000 m^3 (118,000 acre-ft) reservoir behind a dam on the nearby White River, to be constructed by the State of Utah and the Ute Indians. When commercial production is attained (Phases III and IV) water requirements will range from 13,000 acre-feet (16,000,000 m^3) to 26,000 acre-feet (32,000,000 m^3) per year. These could also be obtained from the above-mentioned multi-purpose reservoir, or alternatively, by pumping from the Green River and Flaming Gorge Reservoirs.

Table 2-4. Tracts U-a/U-b - White River Shale Project Summary (23)

	PHASE I	PHASE II	PHASE III	PHASE IV
MINING				
Type	Open Mine (room and pillar)	Development and Operation	Commercial Production	Commercial Production
Production	Nominal	6,700 tonnes/day	72,500 tonnes/day	145,000 tonnes/day
Ore Haulage	Truck	Conveyor	Conveyor	Conveyor
PROCESSING				
Retorting	None	Single Vertical Module	Gas Combustion/ TOSCO II	Gas Combustion/ TOSCO II
Upgrading	None	Gas Treating	Hydrotreating S, NH₃ Recovery	Hydrotreating S, NH₃ Recovery
PRODUCTS				
Pipelineable Shale Oil	None	752 m³/day	8,000 m³/day	16,000 m³/day
Upgraded Shale Oil	None	None	7,650 m³/day	15,300 m³/day
Sulfur	None	2.7 tonnes/day	75 tonnes/day	150 tonnes/day
Ammonia	None	None	187 tonnes/day	374 tonnes/day
Liquid Fuels	None	None	1,240 m³/day	2,480 m³/day
Moisturized Processed Shale	None	6,510 tonnes/day (includes fines)	58,700 tonnes/day	117,400 tonnes/day
WATER DEMAND		870 liters/min.	17 m³/min.	34 m³/min.
POWER DEMAND	3 megawatts	12.5 megawatts	100 megawatts	200 megawatts
PEAK EMPLOYMENT				
Construction	230	900	1,900	2,000
Operation	67	325	800	2,050
ELAPSED TIME				
Construction	1.5 yrs.	3 yrs.	2 yrs.	2 yrs.
Operation	1.5 yrs.	2.5 yrs.	20-30 yrs.	20-30 yrs.

At full-scale production the Project is expected to be self-sufficient in utilities and fuel requirements. Modest quantities of shale oil initially produced will be transported to market by truck. In the commercial phases (III, IV) the upgraded shale oil products will probably be sent by pipeline northeast to Casper, Wyoming, and thence by conventional trans-continental pipeline to refiners.

Environmental Programs

During all three operating phases of the White River Project, fugitive dusts from mining and crushing are to be controlled by the use of water sprays, baffled settling chambers, and wet scrubbers. Wet scrubbers will also be used for particulate emissions control during modular and full-scale retorting.

All of the shale oil produced daily at maximum scale-up will be upgraded in facilities similar to those used for the Colony Operation. As a result, some 3% of the wastes disposed will be spent catalysts, sludges, and arsenic-laden solids from TOSCO II-type shale oil upgrading units. These wastes will be discarded with the retorted shale. Waste disposal is expected to be at Tract U-a, in Southam Canyon, to the west of the plant area. The processed shale pile will be built southward along the eastern half of the canyon, toward the southern limits of Tract U-a. A retention dam at the northern end of the canyon will prevent contamination of the White River. The finished processed shale disposal pile will be contoured to blend with the natural terrain, and revegetated.

It is projected that the 72,500 tonnes (80,000 tons) per day and 145,000 tonnes (160,000 tons) per day commercial operations will collectively dispose of a total of about 1,040 million metric tons (1,150 million tons) of processed shale and plant wastes during the 20 plus years of contemplated full-scale production. This will result in a disposal pile in Southam Canyon of 727 million cubic meters (950 million cubic yards) volume, occupying some 366 hectares (900 acres), with an average depth of 61 meters (200 ft). A two-year baseline environmental monitoring program is proceeding at U-a/U-b.

2.4.4 Federal In-Situ Lease Tract Nominations (35)

In April 1975, the Under Secretary of the Interior called for nominations of areas for leasing to be developed by in-situ technology. Six tracts in Colorado and three in Utah were nominated, and a tract selection committee (composed of state personnel and Department of Interior personnel) recommend[illegible] two preferred and two alternate tracts. The preferred sites are shown in Figures 2-1 and 2-2 as "insitu #2" (Colorado) and "in-situ #8" (Utah). The alternate sites are "in-situ #7," and in-situ #9," in Utah. Major criteria for selecting the preferred sites were:

- Lack of conflicting mineral leases (or absence of minerals associated with oil shale).

- Shale deposits likely to be available only or primarily by employing in-situ extraction methods.

- Absence of ground water
- Socio-economic factors (e.g., local towns likely to be affected)
- Accessibility (e.g., existing roads)
- Environmental considerations

The tract selection committee submitted its recommendations to OSEAP in September 1975. The Oil Shale Environmental Advisory Panel reviewed the selections and recommended four sites for consideration by the Assistant Secretary of the Interior. Final decision on which tracts to be leased awaits preparation of an Environmental Impact Statement.

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3.0 THE NATURE AND SOURCES OF EMISSIONS, EFFLUENTS AND SOLID WASTES FROM SHALE OIL OPERATIONS

The oil shale technologies and development activities reviewed in Chapter 2.0 are likely to be the major contributors to commercial shale oil production in the near future. Each technology and activity will have associated with it certain waste streams and environmental problems. Thus Chapter 3 is a discussion of characteristics of the major technologies which influence the composition, properties, and quantities of wastes which may be generated during future commercial operations. The approximate inventories of waste quantities are presented where information is available. Where appropriate, a brief discussion of planned pollution control practices is included. Section 3.1 is a review of the types, sources, and inventories of atmospheric emissions. Section 3.2 is a review of process water requirements, wastewater characteristics, and wastewater treatment alternatives. Section 3.3 includes a discussion of some important characteristics of raw and retorted shales, an identification of non-shale solid wastes, and a summary of the approximate quantities of such wastes which would be associated with major development activities.

3.1 ATMOSPHERIC EMISSIONS

Atmospheric emissions can arise from several activities or operations during oil shale processing. A breakdown of the more important sources of emissions is presented in Table 3-1. The major source of SO_2, NO_x, and CO is fuel combustion for process heat; SO_2 is also emitted in the tail gases of sulfur recovery operations. The use of fuel oils in mobile equipment and in explosives will result in emissions of CO and NO_x. Hydrocarbons are present in both combustion emissions and in product storage tank vapors. Emissions of particulate matter can result from 1) blasting, 2) raw and spent shale handling and disposal, 3) raw and spent shale dust in process gas streams, 4) fuel combustion, and 5) site activities which generate fugitive dust.*

Emissions of potentially hazardous substances may occur during the extraction and processing of oil shale. Silica (quartz) may be present in dust derived from oil shale and associated rocks and in fugitive dust. Particulate emissions from fuel combustion and fugitive dust from spent shale handling and disposal can contain polycyclic organic material (POM) and certain trace metals. Gaseous ammonia, hydrogen sulfide, and volatile organics may be released during moisturizing and subsequent cooling of retorted shale.

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*Fugitive Dust refers to particulate matter which is discharged to the atmosphere in an unconfined flow stream, generally as a result of mechanical disturbance of granular material exposed to air.

Table 3-1. The Sources and Nature of Atmospheric Emissions from Oil Shale Extraction and Processing

Subprocess	Emission Generating Activity	Potential Criteria Pollutants	Potential Non-Criteria Pollutants
• Oil Shale Extraction	Blasting	PM*(1) Dust*(1), CO, NO_x, HC	Hg, Pb (etc); silica
	Mine equipment use • Fuel use	PM*(2), CO, NO_x, SO_2, HC	silica
	Fugitives	Dust*(1)	
• Raw Shale Transport	Equipment use • Fuel use	PM*(2), CO, NO_x, SO_2, HC	silica
	Fugitives	Dust*(1)	
• Preparation	Crushing Screening Ore Storage	PM*(1)	silica
• Retorting Operations	Shale Preheat • Fuel use • Shale dusts	PM*(1,2), CO, NO_x, SO_2, HC HC's	trace elements
	Heat Carrier Reheating • Fuel use	PM*(2), CO, NO_x, SO_2, HC	trace elements; trace organics
	• Combustion of shale organic material	PM*(2), CO, NO_x, SO_2, HC	trace elements; trace organics
	Spent Shale Discharge • Moisturizing of dry ash	PM*(3), HC's	H_2S, NH_3, volatile and trace organics
• Upgrading and Utility Operations	Process heaters/furnaces • Fuel use	PM*(1), CO, NO_x, SO_2, HC	
• Gas Cleaning Systems	Sulfur recovery and tail gas cleanup	SO_2	H_2S; COS
	Hydrogen production • CO_2 removal	SO_2	COS
	Fuel use	PM*(2), CO, NO_x, HC, SO_2	
• Product Storage	Tank evaporation	HC's	
• Solid Waste Disposal	Equipment use	PM*(2), CO, NO_x, SO_2, HC	trace organics
	Fugitives • Spent shale transport and spreading • Coke, spent catalyst, other wastes - transport and spreading	PM*(3) PM*(3)	metals (As, Cd, Cr, Mo); trace organics

*Suspended particulate matter is the defined criteria pollutant; PM is broken down into 3 general categories in this table:
(1) Raw shale and natural soil dusts
(2) Fuel combustion ash and sooty material
(3) Spent shale dust (including dust from other solid wastes)

Catalyst materials may release particulate matter containing trace metals to the atmosphere during regeneration, handling, or final disposal.

Section 3.1.1 below is a comparison of TOSCO II, Paraho, and Union B retorting processes for potential emissions of criteria and hazardous pollutants. Section 3.1.2 reviews shale preparation, retorting, and upgrading emissions inventories or estimates which have been prepared for oil shale developments. Section 3.1.3 presents an estimate of fugitive dust emissions associated with the extraction of oil shale.

3.1.1 A Comparison of Retorting Processes for Potential Emissions

Potentially commercial surface retorting technologies fall into three classes:

	Class	Examples
(1)	Externally heated recycle solids retorts	TOSCO II
(2)	Gas combustion retorts (GCR)	Paraho Direct Mode
(3)	Externally heated recycle gas retorts	Union B, Paraho Indirect Mode

Generally, the retorting operation itself does not involve atmospheric emissions; gaseous, liquid, and solid streams leaving the retort are handled by downstream systems before reaching an atmospheric interface. However, certain features inherent in the retorting method influence the nature and magnitude of emissions from other sources in the associated shale oil plant. The discussion below focuses on TOSCO II, Paraho, and Union B technologies with emphasis on process stream composition and quantities. Differences in potential emissions for criteria pollutants (SO_2, NO_x, particulates, CO, and hydrocarbons) and hazardous substances (polycyclic organic material and trace elements) are discussed.

It should be cautioned that a comparison of processes for potential emissions (and other wastes) should consider similar sized operations, and appropriate control technologies applied to waste streams. Since processes such as TOSCO II are more advanced and more information is presently available for such processes, waste streams are more well defined than those associated with less developed processes. Conclusions reached in this section are not intended to endorse or condemn a given process, but rather to highlight process features.

Sulfur Compounds: Sulfur in raw oil shale amounts to about 0.7% by weight, approximately 1/3 associated with the organic fraction, and 2/3 as pyrite (Fe_2S) (1). During kerogen pyrolysis, about 40% of the organic sulfur in shale appears as H_2S in the produced gases, and the other 60% as heavier sulfur compounds in raw shale oil and in the spent shale carbonaceous residue. Pyritic shale sulfur does not decompose under non-oxidizing retorting conditions.

A TOSCO II retort produces about 187 M^3 of net gas along with each cubic meter of crude shale oil (1040 SCF per BBL)(2,3). The gas contains about 3-5 volume % H_2S, and the oil about 0.9 weight % total sulfur. The sulfur is partially removed from both oil and gas before in-plant use or sale. Consequently, SO_2 emissions from plant fuel use depend upon both the fuel mix and the degree of sulfur removal from gas and liquid products. Finally, SO_2 can be emitted in sulfur recovery plant tail gases, or in tail gases from subsequent cleanup operations.

A gas combustion retort (GCR) produces a significantly larger volume of gas per volume of oil (~2000 M^3/M^3) (10,900 SCF/BBL) than a TOSCO II retort (4,5). Sulfur in such retort gases amounts to about 0.1% by volume (almost entirely as H_2S). The smaller total quantity of sulfur in GCR retort gas compared to TOSCO II gas may partially reflect the higher grade of raw shale (and associated higher sulfur content) which has been used in the TOSCO II retort than in the GCR retort. Also, the more rapid pyrolysis of kerogen and the shorter residence time of organic vapors at retorting temperatures in the TOSCO II retort may result in more complete conversion of organic sulfur to H_2S. Table 3-2 shows a comparison of total sulfur in TOSCO II and GCR retort gases.

Table 3-2. Comparison of Total Sulfur in Raw Retort Gases (2,3,5,6)

Process	Volume Produced $\frac{M^3\ gas}{M^3\ oil}$	Sulfur in Gas (Vol %)	Weight Sulfur (kg) in Gas per M^3 of Oil
TOSCO II	187	3 - 5	8 - 14
GCR (direct mode Paraho)	2000	0.1 - 0.2	3 - 6

In the combustion zone of a GCR, organic sulfur and pyrite are burned along with the carbonaceous residue of retorted shale. The oxides of sulfur are apparently captured by the alkaline oxide/carbonate minerals remaining in the shale, and are discharged from the retort as sulfite or sulfate salts with burned shale (7,9).

Externally heated recycle gas retorts (i.e., Union B) produce net gas of composition similar to TOSCO II gas. Sulfur content of raw shale oil and of the carbon residue associated with spent shale are also comparable (10,11).

Actual SO_2 emissions associated with individual retorting processes will depend upon the degree of sulfur removal accomplished for in-plant fuels, the extent of on-site shale oil processing, and the degree of control applied to sulfur recovery tail gases.

Oxides of Nitrogen: Combustion of any hydrocarbon fuel will produce oxides of nitrogen when air containing elemental nitrogen is used as the oxygen supply. The extent of NO_x formation from oxygen and nitrogen in air during combustion is related primarily to flame temperature, residence time, and air/fuel mixture. In addition, organic nitrogen contained in fuel can be partially oxidized to NO and NO_2, depending on the above variables and the level of fuel nitrogen. Generally, gaseous fuels tend to emit lower quantities of NO_x than liquid or solid fuels, given comparable combustion conditions and fuel nitrogen levels (13).

Most retorting processes require heat supplied by combustion of retort gases, shale oil, or carbonaceous residue remaining after pyrolysis of shale organic material. Nitrogen in raw oil shale exists as a chemically bound component of the kerogen matrix (1). In TOSCO II retorting about 35% of the original shale nitrogen in shale appears as the sum of ammonia in retort gases and organic nitrogen in crude shale oil. The remaining 65% is found in the retorted shale (with carbonaceous residue) (2). Combustion of raw gas, crude shale oil, or the spent shale carbonaceous residue may result in a partial conversion of the bound N to NO_x.

In the GCR process the residual carbonaceous material associated with "retorted" shale is burned internally in the retort. The recycle gas is known to contain some ammonia but very little NO_x (5,6). Mass balance calculations suggest that the organic nitrogen entering the combustion zone of the GCR is partially converted to elemental nitrogen. However, total ammonia in GCR retort gas and total nitrogen in GCR product oil per ton of input shale is about the same as the totals in TOSCO II gas and oil..

A TOSCO II plant may present a larger NO_x emissions potential than a GCR plant, depending on the quantity and nitrogen level of shale-derived oil which must be used to supplement gas for process heat. Net TOSCO II gas is likely to be of sufficient quantity to supply retorting process heat, but not to supply both retorting and on-site upgrading heat requirements, and feedstock for hydrogen production (2,3). A GCR retort, on the other hand, produces a large excess of low Btu gas over retorting heat requirements, and such gas is available for supplying heat for upgrading processes (it is doubtful, however, that GCR gas could be economically used as a feedstock for hydrogen production) (14).

Particulate Matter (2,3,7,9): Generally, processes which require small sized shale feed (e.g., TOSCO II) will have more uncontrolled particulate emissions during crushing and raw shale handling operations than processes which require large feed (GCR-Paraho). Also, the presence of small raw and retorted shale particles in preheat and elutriator systems of a TOSCO II plant result in a greater particulate emissions control requirement than would be the case with a similar sized GCR retort. Particulates resulting directly from fuel combustion for in-plant purposes are mainly a function of fuel mix; the GCR retort will produce an excess of fuel gas, a TOSCO II operation may have to burn some product oil for process purposes. Moisturizing of retorted TOSCO II shale may require greater particulate emissions control than moisturizing the larger sized GCR retorted shale.

The feed to a retorting plant always presents a particulate control problem. Run-of-Mine raw shale commonly contains about five weight percent of ore of less than 12.7 mm (1/2 inch) size. A sizable percentage of this segment will become minus 100μ particulate as a result of primary crushing.

Fugitive dust emissions may present more of a problem for the TOSCO II process than for GCR or Union process. Ore storage and handling and disposal of the fine TOSCO II retorted shale are potential fugitive sources. However, unusable fines for GCR and Union will require proper handling and disposal in order to minimize fugitive emissions.

Site use activities which may generate fugitive dust are generally not process specific. The use of open pit vs underground mining will be the largest factor determining total fugitive emissions associated with the extraction of oil shale (15).

Hydrocarbons (HC's) and Carbon Monoxide (CO): Emissions of HC's and CO occur during incomplete combustion of fuels in process heaters and in mobile equipment. Hydrocarbons may also be vaporized during product storage. Equipment use and evaporative hydrocarbon emissions are not expected to be process specific.

The TOSCO II retort may present a somewhat greater hydrocarbon emissions control requirement than direct mode Paraho or Union retorting since preheated TOSCO flue gases contain fresh kerogen derived vapors. Incineration of these gases can reduce hydrocarbon concentrations to less than 90 PPM (3). There may be other hydrocarbon sources in Union or GCR retorting that have not been quantified.

The largest source of CO in an oil shale operation is mobile equipment used for mining and transport (3,7). The quantity of such emissions is a function of mining method and haul distances rather than retorting process.

Polycyclic Organic Matter (POM)*: The pyrolysis of essentially any type of organic material produces a certain amount of POM, and oil shale kerogen is no exception (17). Generally, POM compounds have a low volatility and will be associated with high boiling liquid or solid products, or particulate matter.

Although POM is known to be present in carbonaceous retorted shales, the biological availability and potential hazard of such material is not accurately known at present. (See Section 3.3)

Release of POM to the atmosphere during oil shale processing can occur via three major pathways:

(1) Handling and disposal of retorted shale - fugitive particulates and possible volatilization of hydrocarbons.

(2) Combustion of shale derived oils containing POM.

(3) Flue gases containing entrained retorted shale particulates, along with retort gas or spent shale coke combustion products.

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*POM includes polycyclic aromatic hydrocarbons, their nitrogen and sulfur heterocyclic analogues, and their oxidized derivatives.

TOSCO II retorted shale is very fine and contains 4-5% carbonaceous residue. Fugitive emissions may occur during disposal of such shale, and the small sized suspended particles are those most likely to penetrate into and be retained by the lung. TOSCO II preheat system and elutriator system flue gases may contain suspended raw and spent shale particles of very small size even after controls. The use of product oil to supply process heat may contribute to POM emissions.

Union B spent shale is chemically similar to TOSCO II spent shale, but may present less of POM emissions potential during handling and disposal due to the much larger average particle size.

GCR retorting involves the combustion of residual shale carbonaceous material internally, and little organic matter or carbon remains with the retorted shale(s). Consequently, POM is found in much lower amounts in GCR retorted shale than in TOSCO II retorted shale (16). Further, GCR retorted shale consists of pebble sized solids, and is likely to present a low fugitive emissions potential.

Trace Elements: Green River oil shale contains trace amounts of many elements. However, for elements other than Si, Fe, Al, Ca, Mg, Na, and K, the concentrations in oil shale are less than or comparable to those found in common sedimentary and igneous rocks (18). In contrast, petroleum and coal contain greater quantities of metals and other trace elements than common rocks.

Temperatures and redox conditions during retorting are not severe enough to volatilize most metalic and heavy elements. With notable exceptions such as arsenic (As) and possibly antimony (Sb), most trace elements (e.g., nickel (Ni), vanadium (V), Molybdenum (Mo)) remain with the spent shale, or are found as components of raw and spent shale solids entrained in retort gases and in raw shale oil. Arsenic in raw shale apparently forms a range of volatiles, oil soluble compounds (perhaps organic arsines) during retorting, and appears in raw shale oil and all condensible oil fractions (19). If not removed during upgrading, arsenic will be present in shale oil combustion products.

Actual emissions of non-volatile trace elements will be in approximate proportion to raw and retorted shale particulate emissions for an oil shale extraction and retorting operation. Such emissions may not be different in nature or magnitude from those associated with the extraction and processing of other fuel and non fuel minerals (coal, limestone, phosphate rock, etc.). Further, the dolomitic and/or alkaline nature of shale immobilizes many elements as relatively inert oxide, carbonate, or silicate salts. Trace element mass emission rates give no single indication of bioavailability, chemical reactivity, or physical properties.

Metals and their compounds are used as catalysts (Ni, Co, Mo, Cr, Fe, Zn) for hydrotreating, dearseniating, sulfur recovery, and trace sulfur removal (2,3,7,8). Emissions of particulate matter containing catalyst metals can occur either during on-site regeneration or during handling and disposal. Catalyst use is, of course, not unique to shale oil processing, and such information and experience in preventing hazardous emissions can be borrowed from the petroleum and related industries.

3.1.2 Process Emissions Inventories

Quantitative and semi-quantitative emissions information is available for several oil shale technologies and developments. Emissions from process sources are generally known with more certainty than emissions from mobile equipment use, blasting, and fugitive sources. Process inventories for the Colony Development operation and lease tracts C-a, C-b, and U-a/U-b are presented and discussed below. Less complete estimates of emissions are presented for the Union and Occidental processes.

Colony Development Operation - TOSCO II: The basic information about TOSCO II emissions is contained in the Colony Development Operation EIA (1973) (2) and more recently in the Department of Interior's EIS for Colony (1975) (3). Other versions of TOSCO II emissions can be found in SRI (1974) (9) and FEA (1975) (15), although these are based upon data in the Colony EIA. More recently, detailed development plans (DDP's) for federal lease tracts Ca and Cb have presented TOSCO II emissions estimates (7,8). The DDP's have relied heavily upon Colony data similar to that found in the 1975 EIS (3).

Table 3-3 presents four versions of an emissions inventory for TOSCO II retorting and on site upgrading of shale oil. The first three are based upon Colony EIA data. Plant emissions result mainly from fuel combustion, with the preheat system being the largest single source. Colony had assumed a plant fuel mix consisting of about 50% fuel gas, 21% butane fuel, and 29% fuel oil (2). SO_2 and NO_x emissions reflect the sulfur and nitrogen content of fuels, especially the fuel oil. Particulate emissions arise in flue gases both from combustion processes and from the entrainment of raw and spent shale dust. Also, large quantities of particulates are generated during ore preparation.

Colony has revised the TOSCO II emissions inventory in the 1975 EIS (the fourth inventory in Table 3-3). Total SO_2 emissions are dramatically reduced, reflecting greater sulfur removal plans for in-plant fuels. Some modification of the original fuel mix may also be involved, but Colony has not revealed the assumed fuel schedule (or fuel sulfur contents). Total NO_x emissions are also lower in Colony's EIS emissions inventory. It is not known whether greater nitrogen removal from fuels or greater combustion control is responsible for the NO_x reductions. Total process particulate emissions are about the same in the 1973 inventory.

Colony has indicated that Claus sulfur plant tail gas is to be handled by a Wellman-Lord unit for SO_2 removal. SO_2 emissions from the sulfur recovery operation are larger in the 1975 inventory than in the EIA inventory, mainly reflecting an increased H_2S load on the Claus plant from more extensive sulfur removal from shale oil products.

Colony has estimated emissions resulting from mobile equipment use in underground mining, and dust generated during blasting operations. Total carbon monoxide emissions from the mine are much larger than from in-plant operations. NO_x and particulate emissions from the mine constitute around 10% of the total for their respective inventories.

Tract C-b Inventory (8): The developers of tract C-b (Shell and Ashland) are partners in the Colony group, and propose to use TOSCO II technology at the tract. The emissions inventory reported in the recent DDP for tract Cb is essentially identical to that presented in the Colony 1975 EIS and shown in Table 3-3.

Tract C-a Inventory (7): The leasees of tract C-a intend to use TOSCO II retorting for 2/3 of the mined shale and GCR (Paraho) retorting for the other 1/3 during Phase II operations. Table 3-4 presents the emissions inventory for C-a phase II operation (8900 M^3/day, 56,000 BBLS/day) as described in the recent detailed development plan. The emissions directly associated with GCR retorting are those from the shale preheating furnace and from spent shale moisturizing.

The integrated TOSCO/GCR retorting system for Tract C-a differs in several ways from the Colony (TOSCO) system:

- GCR product gas is used to preheat shale for the TOSCO II retort - the integrated system uses entirely gaseous fuels.
- Hydrogen for upgrading is produced by partial oxidation of the 480°C+ (900°F+) shale oil distillate bottoms rather than by the reforming light hydrocarbons. Process energy (and associated emissions) for this operation is supplied by auxiliary boilers.
- A lower average grade of shale (.095 M^3/tonne or 23 gal/ton) is extracted and processed. Total shale preparation emissions for the 8900 M^3/day operation are therefore higher than for the Colony operation (using .146 M^3/tonne or 35 gal/ton shale).

The overall shale preparation and processing emissions associated with the tract C-a operation are comparable to Colony EIS emissions for SO_2. Total NO_x and particulate emissions are lower, reflecting use of low nitrogen plant fuels, better combustion control, and more efficient particulate collection systems.

Tracts U-a/U-b (23): The White River oil shale project plans to develop tracts U-a/U-b probably using primarily Paraho type technology. Fines are to be handled using TOSCO II technology in later phases of tract development. Table 3-5 presents an emissions inventory for Phase III operations ([illegible] m^3/day or 50,000 bbls/day). Total NO_x emissions are comparable to those for similar sized operations at C-a and C-b. Total particulate, SO_2, THC, and CO emissions differ somewhat from those associated with other developments for several reasons including: (1) the inclusion of mining, mobile equipment, and fugitive dust emissions in the U-a/U-b inventory, (2) a combination of

Table 3-1. Comparison of TOSCO II Emissions Inventories (8000 m^3/day) (50,000 bbls/day)

[illegible]

(1)See Ref. 2 at end of Chapter 3.

(2)See Ref. 9 "

(3)See Ref. 15 "

(4)See Ref. 3 "

(5)See Ref. 8 "

Table 3-4. Lease Tract C-a Phase II Emissions Inventory (56,000 bbls/day)[1]

SOURCE	HEAT INPUT 10^6 KCAL/DAY	RETORTING/UPGRADING EMISSIONS (TONNES/DAY)			
		SO_2	NO_x	THC	PART.
Preheat	138	2.164	6.336	3.727	2.600
Elutriator Systems	7.4	5.164	1.385	0.372	1.455
Coker Heater (vent)	3.7	0.001 0.033[4]	0.159	0.023	0.073
Gas Oil Heater	7.0	0.027	0.466	0.037	0.024
Gas Oil Furnace	6.4	0.020	0.173	0.034	0.023
Naphtha Heater	1.9	0.005	0.128	0.010	0.006
H_2 Production	–	0	0	0	0
Aux Boilers	39.5	0.072	1.459	0.731	0.731
Sulfur Plant	0	0.436	0	0	0
TOSCO Shale Moisture	0	0	0	0	0.784
Glycol Reboiler (RM-Gas Plant)	5.8	0.007	4.127	0.033	0.021
H-Plant CO_2	0	0.738	0	0	0
GGH-Preheat	5.6	0.075	0.399	0.029	0.078
GGH Moisture	0	0	0	0	0.007
Process Total	231	3.427	70.617	1.734	5.064
Ore Prep				–	1.255
Storage		–	–	1.746	–
Total	231	3.427	70.617	3.537	6.319

[4]Max 15 min/day

[1]See Ref. 3 at end of Chapter 3.

MINE/CRUSHERS[2]	
SOURCE	PARTICULATES (TONNES/DAY)
Primary Crush	0.130
Secondary Stockpile	0.278
Primary Ore Reclaim	0.142
Secondary Crush	0.647
Fine Ore Storage	0.125
Total	1.255

[2]Based on 2/3 TOSCO
1/3 GCP
105,000 tonnes/day mined

TANK STORAGE	
PRODUCT	THC's[3] (TONNES/DAY)
Naphtha	0.086
Gas Oil	0.027
Diesel	.393
Raw Shale Oil	.020
Resid	.003
Raw Naphtha	.033
Raw Gas Oil	.022
Storage Oil	0.023
H-plant Feed Tank	.007
Coker Tank	.003
Total	1.746

[3]Assumes evaporative component of all stored products to have a specific gravity of 0.84 (60°F/60°F) or 7 lbs/gallon.

Table 3-5. Lease Tracts U-a/U-b Emissions Inventory (50,000 bbls/day) (23)

Source	Heat Input (10^6 Btu/Day)	Tons/Day SO_2	NO_x	THC	Part.	CO
[illegible]						
• [illegible]	—	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
• [illegible]	—	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
• [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
TOSCO II Type Retorts						
• [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
• [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
• [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
• [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Hydrogen Plant	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Crude Shale Oil Hydrotreater	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Naphtha Hydrotreater	[illegible]	[illegible]	[illegible]	—	[illegible]	[illegible]
Utility Boilers						
• [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
• [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Sulfur Plant	—	[illegible]	—	—	—	—
Process Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Source	Heat Input (10^6 Btu/Day)	SO_2	Tons/Day NO_x	THC	Part.	CO
Mining Operations						
• [illegible]					[illegible]	
• Blasting	[illegible]		[illegible]		[illegible]	[illegible]
• [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Mine Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Ore Preparation						
• [illegible]	—				[illegible]	
• [illegible]	—				[illegible]	
• [illegible]	—				[illegible]	
• [illegible]	—				[illegible]	
Ore Prep Total					[illegible]	
Tank Storage	—			[illegible]		
Processed Shale Disposal						
• [illegible]					[illegible]	
• [illegible]					[illegible]	
• [illegible]					[illegible]	
• [illegible]	[illegible]	—	[illegible]	[illegible]	[illegible]	[illegible]
Disposal Total	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]
Tract Totals	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Direct and Indirect Mode Paraho retorting, and TOSCO II retorting, (3) hydrotreating of crude shale oil, and (4) the use of fuel oil in utility boilers. A detailed comparison of emission source contributions to the total inventories for U-a/U-b, C-a, and C-b has not been undertaken for the preparation of this report.

Union B Process (20). A complete emissions inventory for the Union B process is not available at present. However, company personnel indicate that three major emissions sources will be present in the first generation Union B plant at the Parachute Creek site: (1) flue gas from the recycle gas heater, (2) sulfur plant tail gas, and (3) flue gas from the arsenic removal preheater. A normalized emissions inventory for a Union B plant cannot be directly compared to an inventory from Colony or C-a, since Union does not envision on-site upgrading during initial operation.

Net product gas from the Union retort is expected to be similar in composition and heat value to TOSCO II retort gas. After sulfur removal, Union reports the following emissions from combustion of this gas:

Table 3-6. Union B Fuel Gas Combustion Emissions (20)

Plant Size M^3 oil/day (BBLS/day)	Gas Firing Rate M^3/day (ft^3/day)	SO_2 Emissions tonnes/day (tons/day)	NO_x Emissions tonnes/day (tons/day)
1260 (7920)	1.9×10^5 (67×10^5)	0.33 (0.36)	1.0 (1.1)
8000 (50,000)	12.2×10^5 (430×10^5)	2.08 (2.29)	6.2 (6.8)

A Stretford unit will be used to remove H_2S from Union retort gases. Off gas from the Stretford Unit will contain small amounts of sulfur compounds (CS_2, COS, H_2S). Union has not disclosed its estimate of such emissions, but the quantity is likely to be small relative to fuel gas combustion emissions.

A small quantity of fuel gas is to be used in a heater in Union's arsenic removal process. The amount of fuel used (and emissions) is considered a proprietary part of the process.

The Union B process features spent shale moisturizing and discharge from the retort via a water seal. Particulates associated with shale moisturizing are collected in this process with the condensed steam.

The Union B retort accepts a somewhat smaller sized raw shale as feed than a GCR retort. The quantity of uncontrolled particulate emissions from shale preparation might be expected to be somewhere between that from a comparably sized GCR and a TOSCO II operation.

Superior Process. The Superior process combines certain features of gas combustion retorting (Paraho Direct Mode) and inert gas retorting (Paraho

Indirect Mode). On-site use of low and high Btu gas for process and upgrading purposes will result in emission control requirements similar to those for Paraho retorts. Superior has not developed its process to the point of being able to define such emissions to date.

Occidental (In-situ): A modified in-situ operation and associated surface plant would be expected to product uncontrolled emissions similar to above ground retorting processes. Mining is required and the associated mobile equipment emissions and dust emissions would be similar to those associated with the mining for above ground retorting (on a unit mined shale basis).

Since the in-situ retort is operated in a gas combustion mode, large quantities of low Btu gas (700 Kcal/M^3 or 80 Btu/SCF) are commonly produced during in-situ retorting (22). Occidental reports that such gas contains around 0.6% total sulfur and some ammonia (21). The economic practicability of removing hydrogen sulfide from the retort off-gas prior to combustion, especially if electric power generation with the low-Btu gas proves to be feasible, remains to be ascertained. In a previous study for the Federal Energy Administration conducted by TRW (15), the quantity of vent gas released to the atmosphere was estimated to be 625 M^3/sec (1,400,000 ft^3/min) for a 5860 M^3/day (36,800 BBLS/day) in-situ operation retorting .08 M^3/tonne (18 gal/ton) shale. This is equivalent to a stack gas emission rate of 839 M^3/sec (1,777,000 actual ft^3/min) at 95ºC (209ºF), and comparable in magnitude and composition with the stack gas emitted from a 500 MW oil-fired electric power plant.

In-situ produced wastewaters will likely contain NH_3 and H_2S, which could be released to the atmosphere if such waters were to be disposed of by evaporation (i.e., in surface ponds).

If product upgrading is performed on site, emissions will be associated with such processing. However, Occidental does not envision upgrading at present. A quantitative estimate of emissions associated with the Occidental process will have to await the design of surface plant for handling product oil, gas, and wastewaters. Occidental has filed certain emissions data with the State of Colorado, but this data is not currently public information.

Summary of Air Pollution Control Technology: Table 3-7 presents the major sources of SO_2, particulate, NO_x, hydrocarbons, and carbon monoxide from the preparation and processing of oil shale to upgraded shale oil products. The major proposed air pollution control equipment and/or techniques to reduce these emissions are listed in the table, along with some comments about the emissions inventories which have been presented and discussed above.

3.1.3 Fugitive Emissions Inventories

Table 3-6 presents one estimate of fugitive emissions associated with oil shale operations. Uncontrolled fugitive particulates could constitute a large fraction of a total particulate inventory at a development site. Shale preparation and process particulate emissions for a 8000 M^3 (50,000 bbls) per day) plant are about 5 to 10 tonnes/day (Tables 3-3 and 3-4), while

Table 3-7. Summary of Air Pollution Control Technology for Oil Shale Preparation and Retorting, and Shale Oil Upgrading

Pollutant	Control Technology	Comments About Emissions Inventories
SO_2 (and total sulfur) • Gas	Fuel Desulfurization • Amine/ammonia/H_2O scrubbing • Stretford sulfur removal/recovery • Claus sulfur removal/recovery • Sulfur plant tail gas cleanup : Wellman Lord	Differences in SO_2 inventories reflect: • Fuel mix • Degree of hydrotreating • Efficiency of S removal from fuel gas • Sulfur plant tail gas cleanup Recent Colony and LR inventories assume cleaner fuels than earlier Colony and SRI inventories. Ca and Union inventories based on entirely gaseous plant fuels.
• Oil	Hydrotreating followed by off-gas H_2S and ammonia removal	
Particulates • Retort Feed Preparation	• Covered conveyors • Water spray at transfer points and at storage • Baghouses with induced draft fans	Early Colony efficiency lower than SRI assumptions. Recent Colony, Ca, Cb inventories in approximate agreement (unit shale basis).
• Retorting/oil Recovery	• Dry cyclones • Venturi wet scrubbers	Early Colony efficiency assumptions differ from SRI. Recent Colony, Cb, Ca estimates are comparable on a unit shale basis.
• Upgrading	• Clean fuels	Fuel mix accounts for major inventory differences.
• Shale Moisturizing	• Venturi wet scrubber • Water seal (Union)	SRI assumes greater efficiency than Colony, Ca, Cb. TOSCO II generates more particulates during moisturizing than does MIS. Union uses water seal; claims no emissions from this source.
NO_x Gas Fuels Liquid Fuels	• Ammonia removal • Hydrotreating/ammonia removal from off gases	Early Colony EIS assumed high nitrogen shale oil used as plant fuel. Recent Colony and Cb inventories assume low N fuels. Ca and Union inventory based upon entirely gaseous fuels.
HC's and CO	• Incineration of trace hydrocarbons in TOSCO II preheat system	All inventories comparable for HC's. Diesel equipment/mine vent rather than process sources contribute most CO.

Table 3-6. Potential Fugitive Dust Emissions[a]

Type of Mining Operation	Land Required (Hectares/yr)	Particulate Emissions (Tonnes/Day) Uncontrolled	Particulate Emissions (Tonnes/Day) Controlled
Surface Mine (8000 M^3 oil/day)			
Mine development	10	0.17	
Overburden Disposal	200	3.31[b]	
Temporary Storage	30	0.075	
Permanent Disposal Processed Shale	30	0.50	
Surface Facilities (8 Kilometers of unpaved road, VMT 80 Kilometers)		0.004	
Haulage from Mine (3 Kilometers)		0.070	
		4.13	0.83[c]
Underground Mine (8000 M^3 oil/day)			
Mine development	4	0.067	
Permanent Disposal of processed shale	30	0.50	
Surface Facilities (8 Kilometers of unpaved roads; VMT 80 Kilometers)		0.01	
		0.57	0.11[c]
True In-Situ Processing[d] (8000 M^3 oil/day)			
Surface Facilities (8 Kilometers unpaved road; VMT 80 Kilometers)	-	.01	
		.01	.003

[a] Amick, Robert, S., et al., Fugitive Dust Emission Inventory Techniques, paper number 74-58 presented at the Air Pollution Control Assoc. meeting in Denver, Colorado, June 1974.

[b] Emissions from overburden disposal will likely be much less for the oil shale industry. Revegetation is planned for the disposal area. This will minimize fugitive losses from this source.

[c] Assuming an average of 80% control by applying various air pollution strategies to minimize particulate emissions.

[d] Without mining to create void volume. Emissions associated with a 8000 M^3/day modified in-situ operation would amount to about .06 - 0.1 tonnes/day (uncontrolled), depending on the extent of mining.

uncontrolled fugitive emissions could amount to 4 tonnes/day for a surface mining operation. As would be expected, underground mining presents less of a fugitive dust problem than deep surface mining. Estimated fugitive emissions after control are comparable in magnitude to controlled particulate emissions from shale preparation in a TOSCO II operation.

The emissions inventory for Phase III operations at tracts U-a/U-b include estimates of fugitive emissions from several sources. Approximately 5 tonnes/day of dust are to be attributed to such sources for the 8000 m^3 (50,000 bbls) per day operation (Table 3-5).

3.2 WATER REQUIREMENTS AND WASTEWATER PROCESSING

Water is a necessary resource for the development of an oil shale industry. Water is required for dust control during mining and crushing, for gas cleaning and air pollution control, for cooling purposes, and for moisturizing of retorted shale. Upgrading of crude shale oil, on site power generation, and revegetation of disturbed land and retorted shale disposal areas will also consume large quantities of raw water. The total quantity of water necessary for each of these uses is dependent on the development options chosen and on the ultimate size of the oil shale development.

In recent years, increasingly stringent wastewater discharge regulations have been promulgated by both the federal and state agencies. Because of these regulations, the quality and quantity of wastewater effluents and the frequency of waste disposal may be limited. Most of the oil shale developers however, plan no direct discharges to receiving streams.

The following is a discussion of water requirement estimates, sources and nature of wastewaters, specific process wastewaters, and wastewater treatment options for the oil shale industry.

3.2.1 Water Requirement Estimates for Oil Shale Development

The water requirements per unit of net product will necessarily depend on the type of mining, retorting, and upgrading processes utilized. In general, the in-situ methods are expected to require less water than conventional mining and retorting. Estimated water requirements for an integrated oil shale industry which have been prepared for various oil shale developments are summarized in Table 3-9.

Table 3-9. Estimates of Process Water Requirements for Full Scale Oil Shale Production (m^3 of water needed per m^3 of oil produced) (3,7,8,9, 14,22,23)

Oil Shale Development	Quantity Required (m^3 water/m^3 oil
Tract C-a - Phase II	3.5
Tract C-b - Phase III	3.84
Tract U-a/U-b - Phase IV	5.4
Colony Development Operation	3.84
Union Oil Development Operation	1.56
Occidental	1.0-1.5
Paraho	3.37

Estimates have been made to categorize water consumption by unit processes and operations within a shale oil recovery operation. Table 3-10 is one such estimate of the water requirements by unit processes (4).

Table 3-10. Water Consumption Requirements for Unit Processes Associated with Oil Shale Processing

	Water Requirements m^3 water/m^3 oil production
A. Processes	
Mining and Crushing	0.16 - 0.22
Retorting	0.25 - 0.31
Shale Oil Upgrading	0.62 - 0.93
Processed Shale Moisturizing	1.23 - 1.87
Power Generation	0.31 - 0.43
Revegetation	0 - 0.30
Sanitary Use	0.01 - 0.02
Subtotal	2.57 - 4.07
B. Associated Urban Development	
Domestic Use	0.29 - 0.39
Domestic Power	0.03 - 0.04
Subtotal	0.32 - 0.43
GRAND TOTAL	2.89 - 4.5
AVERAGE VALUE	3.69

More than 80% of the estimated water demand is attributable to the processing facilities. Of the total process water, approximately 45-50% is consumed in moisturizing processed shale. Shale oil upgrading accounts for about 25% of the total process water demand. Power generation and retorting each consumes 10-15% of the water requirement for processing oil shale and shale oil.

3.7.7 Sources and Nature of Wastewater (1,3,7,8,9,12,14,22)

Aqueous wastes from oil shale processing can be broadly categorized as originating from direct or indirect sources. Direct sources are wastewaters generated from unit operations and/or processes, including (1) wastewater from retorting operations, (2) wastewater from upgrading operations, (3) water from air emission control and gas cleaning systems, (4) cooling water and boiler water blowdowns, (5) water treatment systems, (6) mine dewatering wastewaters and (7) sanitary wastewaters. Indirect sources include: (1) leachate from retorted shale disposal areas, (2) runoff and erosion resulting from construction and site use activities, and (3) runoff from mining and transport activities. The following is a discussion of the characteristics of the wastewaters from each of these sources.

Wastewater from Retorting Operations: Water is a direct product of oil shale retorting, resulting from the pyrolysis of kerogen, the release of free and inorganically bound water from raw shale, and the combustion of organic material in shale. From 4 to 30 liters of water (1-8 gallons) are commonly produced per ton of input shale feed to a surface retort, depending on the retorting process and the composition of the shale processed (1,3,14). In-situ process demonstrations have reportedly produced even greater amounts of water (22). Some water condenses with crude shale oil during separation of the oil from retort gases. This water can partially separate from crude shale oil during storage, or can appear in aqueous waste streams of shale oil upgrading operations. Water remaining in retort gases after oil separation can be condensed during cooling or gas cleaning operations, or can appear in the flue gas stream from retort gas combustion. Water separated from crude shale oil contains mainly ammonia, carbonate and bicarbonate, sodium, sulfate, chloride, and dissolved or suspended organic compounds (phenolics, amines, organic acids, hydrocarbons, mercaptans). Smaller quantities of calcium, magnesium, sulfides, and trace elements may also be present, along with suspended shale fines. Water condensed from retort gases contains primarily ammonia and carbonates, with traces of organic substances and sulfur containing compounds.

Process Water from Upgrading Operations: The quality of the wastewaters from an upgrading operation varies with the level of on-site upgrading or refining utilized. In general, a full scale refining operation may include any of the following wastewater streams: oily cooling water, process water, and wash water.

Oily cooling water includes all wastewater resulting from quenching, vessel cleanout, spills, coker blowdown and process steam condensation. Process wastewater includes condensed steam from stripping operations, wash water from process drum cleaning operations, wastewaters produced during chemical reactions, and other in-process sources. Spent caustic streams can result from extraction of acidic contaminants. Wastewaters from sources such as ion exchange regeneration, in-plant storm water, hydraulic decoking and once-through cooling are mostly oil free.

The blending of wastewaters from a full scale refining operation may produce a wastewater high in ammonia, bicarbonates, sulfides, phenols, total dissolved solids, oil and grease. Such waters may be characterized by high levels of Biochemical Oxygen Demand (BOD) and Chemical Oxygen Demand (COD).

Water from Air Emission Control and Gas Cleaning Systems: Included in this category is wastewater collected during retort gas cleaning, tailgas cleanup, and foul water stripping. Major constituents in such waters are shale dust particulates, hydrocarbons, H_2S, NH_3, phenols, organic acids and amines. Other constituents such as thiosulfate and thiocyanate may also be present.

Cooling Water and Boiler Water Blowdowns: Cooling water is used in retorting and oil upgrading to absorb heat which cannot be economically recovered for use in the complex or absorbed by air fan coolers. Cooling water is generally circulated through a wet cooling tower system to release this heat to the atmosphere. Because of evaporative losses, there is a constant build-up of dissolved solids which requires a portion of this recirculated water to be discharged as blowdown from the cooling water system. Similarly a fraction of the boiler water must be discharged as blowdown to minimize scaling of boilers. Both the cooling water and the boiler blowdown waters contain a high concentration of dissolved solids, and substances such as hexavalent chromium used for corrosion control.

Raw Water Treatment System Wastewater: Good quality water is needed to supply processing, cooling tower, steam generation and other miscellaneous process uses. Wastes from water treatment systems generally consist of chemical sludges, backwash water from filtration system and blowdown from zeolite softening systems. The largest quantity of waste is lime sludge which is characterized by high hardness and dissolved salts content.

Mine Dewatering Wastewater: Waters found in aquifers encountered during mining must be removed by a dewatering system. Mine dewatering could produce large quantities of low quality water unless groundwater is prevented from entering the mine. The quality and quantity of this water will vary with location and processing technique. During a full scale operation, most of this water will be used in wetting and compacting retorted shale. Major constituents of mine water are sodium, carbonate, bicarbonate, chlorides, fluorides and boron. Reinjection of this water into the aquifer may cause increased ground water salinity.

Sanitary Wastewater: Included in this category are wastewaters from domestic sewage, kitchen, bathroom, laundry and toilet uses. In addition to the mineral and organic matter already present in the water supply system, human excrement, paper, soap, dirt, food wastes and other substances are added to wastewater. Because of the unstable organic matter and the enteric microorganisms present, disposal of this wastewater without pretreatment is objectionable both from the health, environmental, and esthetic points of view.

Leachate from Retorted Shale: As discussed in the water requirement section, approximately 45-50% of the water required for an oil shale plant is used for moisturizing of retorted shale. Much of this water requirement will be supplied by mine water and process wastewaters. Because of the large quantities of water utilized and the exposure of retorted shale to rain and snowfall, a source of indirect water pollution may occur via leaching or run off from retorted shale piles. However, the bulk of the water applied to retorted shale is expected to be held in capillarity or to be bound as simple hydrates. The suspended and dissolved constituents of wastewaters applied to retorted shale are expected to be partially immobilized by physical adsorbtion and/or chemical reaction with retorted shale. Leaching experiments in the laboratory and with small plots indicate that inorganic salts - Na, Mg, SO_4, Cl^- may be leached from retorted shales. Small quantities of organic substances and trace elements are also water soluble. Leachates are further discussed in Section 3.3.

Runoff and Erosion from Construction, Mining, Transport, and Site Use Activities: Construction, mining and site use activities may potentially result in increased sediment and dissolved solids loading in surface runoff and receiving streams. This indirect source of potential water pollution is not unique to oil shale extraction and processing, but may require careful control due to the magnitude of site activities. Collection and impoundment of runoff will likely be necessary.

3.2.3 Specific Process Wastewaters

The following is a summary of the available process wastewater information. Waste stream information for some processes are not yet available or are considered to be proprietary.

TOSCO II Wastewater (3,8): Direct wastewater discharge from a TOSCO II retorting and upgrading operation is not anticipated. All wastewater is to be reused for in-plant processing and ultimately consumed in moisturizing retorted shale. Plant process wastewaters will be collected, processed to reclaim useful components, and combined for in-plant treatment before reuse. The major process units that generate wastewater are: (1) pyrolysis and oil recovery units - blowdown wastewater is produced from high energy venturi wet scrubbers used to remove shale dust from the flue gas; (2) gas oil and naphtha hydrogenation units - sour water is produced by the washing operation; (3) ammonia separation and sulfur recovery units - ammonia stripped water and an acidic wastewater are generated; (4) delayed coking process units - foul water is produced; (5) utility boilers - blowdown wastewater is produced; and (6) Wellman-Lord unit - blowdown consisting of alkaline sulfate/sulfite wastewaters.

Detailed quantitative characterization of the individual waste streams has not been performed to date because these streams are combined, treated in-plant and subsequently reused to exhaustion. However, the combined process waste stream has been approximately quantified by Colony and is reproduced in Table 3-11. The major constituents present in the combined process water are organic acids, neutral oils, amines and phenols, and mineral salts such as sodium, calcium, and magnesium sulfates, chlorides and carbonates. Data on the exact chemical composition of the organic acid, amine, and

Table 3-11. Approximate Composition of TOSCO II Combined Process Wastewater (8000 m^3/day upgraded shale oil production) (3)

Component	Concentration in Water (mg/l) Added to Spent Shale	Kg/hr
Ca^{+2}	280	86
Mg^{+2}	100	32
Na^{+1}	670	204
NH_4^{+1}	16	4.5
Zn^{+2}	5	1.8
As^{+5}	.015 - 0.3	.0045 - .09
Cr^{+6}	2	.45
CO_3^{-2}	360	109
HCO_3^{-1}	100	32
SO_4^{-2}	850	261
$S_2O_3^{-2}$	90	27
PO_4^{-3}	5	1.8
Cl^{-1}	570	175
CN^{-1}	5	1.81
Phenols	315	98
Amines	410	127
Organic Acids	1,330	409
Neutral Oils	960	295
TOTALS (Rounded)	6,100	1,870

In addition to above, elements present in trace quantities (less than 1 mg/l are Pb, Ce, Ag, Mo, Zr, Sr, Rb, Br, Se, Cu, Ni, Co, Fe, Mn, V, Ti, K, P, Al, F, B, Li.

neutral oil fractions are not available. High molecular weight organics belonging to the polycyclic organic material (POM) class may also be present. Twenty-two trace elements have also been identified as constituents of combined wastewater; none of these, however, is present in quantities greater than 1 mg/l.

GCR (Paraho Direct Mode) Wastewater: Available information from the Paraho Demonstration Project indicates that the major constituents present in process water (condensed or separated from crude shale oil or retort gases) are ammonia, carbonates and bicarbonates, organic acids, and amines (1,5,6). Table 3-12 is a summary of the major constituents present in the Paraho retort wastewater stream and does not reflect any downstream processing operations. Because of the significant amounts of organic material present, the biochemical oxygen demand (BOD) and chemical oxygen demand (COD) are very high.

Table 3-12. Paraho (GCR) Process Wastewater Analysis (1,5,6)

Constituents	Concentration Range (mg/l)
Ammonia nitrogen	2,000-20,000
Organic carbon	10,000-29,000
Organic nitrogen	4,000-12,000
Carbonates	2,000-24,000
Bicarbonates	5,000-26,000
Parameters	
BOD	5,000-12,000
COD	17,000-20,000

Levels of approximately twenty metals have also been determined in Paraho process waters (6). Their concentrations are all less than 1 mg/l. Upgrading of shale oil is not currently practiced at Anvil Points, and little is known about wastewaters which may be associated with such practices.

Union Oil Retort B Process (20): The major wastewater streams from Union Oil's retorting process are: (1) water from make gas compression and cooling, (2) water from ammonia absorption, (3) water from oil-water separation, (4) water from first stage solids removal, and (5) water from oil stripping. According to Union, these wastewater streams will be combined, stored and reused for retorted shale cooling in the water seal after oil water separation and some water stripping. The total quantity of wastewater generated for a 9000 tonnes/day (10,000 TPD) oil shale plant is estimated at 1.32 m^3/min (350 gpm). Because of the proprietary nature of the Union process, quantitative information on waste stream composition has not been made available. Limited information released by Union personnel indicates that the predominant inorganic constituents present in their combined process wastewater are sodium, calcium, and sulfate. Some magnesium, potassium, and bicarbonate are also present, and the total dissolved solids is estimated at 10,000 ppm. No information is available regarding organic constituents or trace elements.

Lease Tracts: The characteristics of process wastewater streams have not been reported for Tracts C-a or C-b. Because of the similarity in retorting operations between C-b and Colony (3,8), it is expected that C-b's process wastewater will be comparable to that reported for Colony. Tract C-a will utilize 35% Paraho (GCR) retort process and 65% TOSCO II process in its Phase II development. Consequently process wastewater generated at C-a will have a composition reflecting both TOSCO II and Paraho retorting.

Developers of Tracts U-a and U-b in Utah plan to process oil shale using primarily Paraho retorts during Phase III. Some of the reported characteristics of process wastewaters associated with Phase III operations at U-a/U-b are shown in Table 3-13 (23).

3.2.4 Process Wastewater Treatment

Under current planning, most of the oil shale developers envision zero discharge of their wastewaters. Reasons for this commitment may be (1) the relative scarcity of water in the western oil shale regions, which may encourage minimum intake and discharge of waters, (2) future pollution control regulations for wastewater discharge which may be so stringent that cost for discharge compliance may well exceed the cost of simple in-plant treatment and subsequent reuse, and (3) control technologies for in-plant treatment which have been well developed by the oil refining industries can be applied to oil shale processing without resorting to high cost research. Consequently, it is anticipated that most of the developments will employ treatment techniques similar to those developed by the oil refining industries. The final disposition of wastewater will be evaporation or incorporation into retorted shale.

The degree of treatment utilized will necessarily depend on the intended reuse of the wastewater. For the purpose of this discussion, the treatment techniques will include both the in-plant and end-of-pipe treatment options. In-plant controls are designed primarily to reduce the volume and quantities of contaminants discharged in process wastewaters. End-of-pipe controls, on the other hand, are designed to treat the wastewaters after they have been generated.

In-plant treatment includes: (1) collection of all process wastewaters and waters from leaks, drain outs, flushes, washdowns, and runoffs; (2) preprocessing of certain waste streams to reclaim valuable constituents; and (3) combining of the various waste streams for solids settling and oil-water separation. A typical in-plant treatment system will consist of individual waste collection lines, ammonia stripping, a sulfur recovery system for specific process streams, a combined waste holding pond, a gravity API separator,* a chemical dosage tank, a dissolved air flotation unit (DAF) and a final holding pond for the treated wastewater.

Wastewater from the foul water system will be stripped with steam to remove dissolved hydrogen sulfide and ammonia. Gases from the stripped overhead will be sent to the sulfur recovery plant and to the ammonia recovery system while the stripped water will be pumped directly to a holding tank or pond for later use in moisturizing spent shale.

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*American Petroleum Institute (recommended design)

Table 3-13. Approximate Composition and Flow Rates for Selected Wastewater Streams - Lease Tracts U-a/U-b (Phase III, 8000 m^3 Upgraded Shale Oil/Day) (23)

Component or Parameter	Units	Waste Stream			
		Sour Water Stripper Bottoms	Oily Wastewater	Treated Low-TDS Wastewater	High TDS Wastewater
Total Dissolved Solids (TDS)	mg/l		500-2000	1000-2000	5000-10,000
Suspended Solids (SS)	"		30-55	30	100-500
Chemical Oxygen Demand (COD)	"	500-1500	100-2000	50	
Biochemical Oxygen Demand (BOD)	"		50-500	20	
Oil and Grease	"	50-100	50-1000	<5	
Phenols	"	80-150		<1	
Ammonia	mg/l as N	25-50			
Flow Rate	m^3/min	12.7	4.1	10.4	10.7

All oily wastewaters from processing, including gas condensates, oily water wash-down from process pads, and process leaks will be collected in a common sump. Overflow from the sump will be conveyed to an API separator system, consisting of a surge pond, an API separator, a chemical dosage tank and a DAF unit. Separated oil will be returned to the raw oil recovery plant and any sludge collected will be removed periodically and returned to a retort or burned in the thermal oxidizer. Effluent from the API separator will flow to the chemical tank where it will be saturated with air by pressurizing the tanks to 40 to 60 psig. After about 1 minute retention, the wastewater will be discharged through a flotation chamber where air will come out of solution in minute bubbles. The residual oil and particulates will be carried to the surface by the bouyant force and will be skimmed and returned to the raw oil recovery plant. Processed effluent will then be sent to a holding pond from which the wastewater will be used for moisturizing and compacting spent shale.

Sanitary wastewaters will be collected and treated in packaged treatment units. Effluent from the treatment unit will be chlorinated and reused as make-up water for certain processes.

Mine dewatering wastewater, runoffs, and blowdowns from cooling tower and boilers will not be treated in the conventional sense. These wastewaters will be centrally collected for use in dust suppression and/or conveyed to the holding tank or pond for wetting of retorted shale.

End-of-pipe treatment includes: (1) additional treatment of the process wastewater after in-plant treatment, (2) treatment of sanitary wastewater, (3) demineralization of mine dewatering wastewater and boiler and cooling water blowdown. Process units utilizing end-of-pipe treatment may include any one or more of the following: biological treatment units such as activated sludge system, biofiltration, or aerated lagoons, demineralization units such as ion exchange columns, reverse osmosis or distillation, and soluble organics removal units containing activated carbon filtration.

3.3 SOLID WASTES ASSOCIATED WITH OIL SHALE EXTRACTION AND PROCESSING

The solid wastes resulting from oil shale processing present one of the major environmental problems associated with commercial development. Shale derived solid wastes include fines from crushing and conveying of the raw shale and the processed (or retorted) shale remaining after retorting. Together these constitute most of the process solids requiring disposal. Other solids to be discarded depend primarily upon the extent of upgrading of the crude shale oil which is carried out in conjunction with the retorting operations, and may include shale oil coke if experience shows that such material is not usable or marketable. Certain non-shale wastes such as spent catalysts may also be generated during the processing of shale oil. This chapter deals with the nature and sources of solid wastes from oil shale processing and presents data on the quantities of solid wastes expected from the various oil shale processing operations.

3.3.1 Raw Shale Fines

The primary sources of raw shale fines are the crushing operations conducted on the as-mined shale, and dust from raw shale transport within the mine-plant complex. The composition of the fines, of course, is essentially that of the mined, raw shale and its contained organic matter. A typical chemical analysis of the organic matter would include the following (1):

	wt %		wt %
Carbon	80.5	Sulfur	1.0
Hydrogen	10.3	Oxygen	5.8
Nitrogen	2.4		

The associated mineral matter in the raw shale has the following typical composition:

	wt %		wt %
Dolomite	32	Albite	10
Calcite	16	Microcline	6
Quartz	15	Pyrite	1
Illite	19	Analcite	1

Oil shale is a highly consolidated organic-inorganic rock system, with no significant micropore structure, pore volume, or internal surface. Over 99% of the inorganic particles have equivalent spherical diameters of less than 44 microns, 75% are 2-20 microns, and 15% are less than 2 microns.

The size distribution of the raw shale fines or rejects from crushing depends upon the feed size requirements of the retort. For the Union retort B, the feed is 3 mm to 5 cm (1/8 to 2 in.), and the fines are therefore minus 3mm (1/8") (20). Paraho fines are typically minus 6 mm, as are also the fines from the Superior process (5). There are no unusable fines from the TOSCO II process (3). The size range of the dust collected from the various processes has not been reported, but can be expected to be less than the average size of the fines from crushing. Dust will probably normally be disposed of as a slurry or sludge.

3.3.2 Retorted Shales

Pyrolysis of oil shale results in the conversion of most of the original organic material in raw shale to gaseous and liquid hydrocarbons (and sulfur, nitrogen, and oxygen containing organics). Retorted shales containing solid organic residues can be disposed of directly as a solid waste, or can be further processed for recovery of heat value of the residue.

Burned Shale (e.g. Paraho Direct Mode (GCR)): After retorting at approximately 900°F, the remaining processed shale is soft and friable. It usually has an organic "carbon" content of 2 to 3%, depending upon the retorting process. Direct Mode Paraho retorting produces a retorted shale which has been partially "burned" after pyrolysis of oil shale kerogen. Residual organic carbon amounts to about 2% by weight, and typically 30% of the contained carbonate minerals have been calcined (24). Particle size is greater than 1.2 cm (0.5 inch). It is possible, in principle, to oxidize this carbonaceous material, as a source of process energy, and to discard a completely carbon-free shale residue, or ash. A typical composition of such ash is shown in Table 3-14 for several retorted shale residues.

Typical shale ash has a composition similar to Portland cement and has certain cement-like physical properties. The cement forming tendency of burned shale can be used to advantage to help create a physically and chemically stable disposal pile (26). Before setting, burned (and moistened) shale ash behaves like a sandy silt. After setting, it develops sufficient cohesion so that deep, well-stabilized piles with high slope angles may be constructed. The strength of burned shale disposal pile depends upon the amount of moisture added (10% is optimum) and the amount of cohesive hydrates produced. Approximately 90% of its ultimate stability is reached in the first 16 days of storage. Reduction in ash particle size, by grinding, increases pile strength.

Carbonaceous Retorted Shale (TOSCO II, Union B, Paraho Indirect Mode): Several retorting processes do not utilize completely the carbonaceous residue remaining on the shale after pyrolysis, as a source of energy. Therefore, the retorted shale still contains about 3% organic matter. In addition, the maximum temperature during retorting is commonly less than that at which the dolomite and calcite in the shale rock decomposes, or at which calcium silicates form.

Cementation reactions produced by subsequent moisturizing of carbonaceous retorted shale do not occur during compaction. There is, therefore, less opportunity to create a water impervious disposal pile, except through the cohesion produced by compaction alone. The possibility of leaching of soluble salts from the pile is therefore greater than is the case with burned shale.

Table 3-14. Ash Composition of Typical Retorted Oil Shales

Component	TOSCO II[a] wt%	Union B[b] wt%	GCR[c] wt%
SiO_2	33.0	31.5	43.8
Fe_2O_3	2.5	2.8	4.6
Al_2O_3	6.8	6.9	12.2
CaO	15.8	19.6	22.1
MgO	5.3	5.7	9.3
SO_3	-	1.9	2.2
Na_2O	0.7	2.2	3.4
K_2O	3.3	1.6	2.4

[a] Colony Environmental Impact Analysis, 1974 (data represent Mahogany zone shale (~35 gal/ton) from Parachute Creek area. See Ref. 3.

[b] Lipman, S. C., Union Oil Co. Revegetation Studies (data represent Mahogany zone shale (~35 gal/ton) from Parachute Creek area. See Ref. 12.

[c] Stanfield, et.al., Data represent Mahogany zone shale (~30 gal/ton) from Anvil Points. See Ref. 25.

TOSCO II retorted shale contains approximately 4.5% organic "carbon," and is to be moisturized to about 14% H_2O for compaction (3). The retorted shale has a very small particle size with 60% finer than 200 mesh, and 35% finer than 325 mesh. The particles are crystalline and bulky, not platy. A typical ash composition is shown in Table 3-14.

Union B retorted shale is similar in size to that produced by the Paraho process. It is a coarse, gravel-sized black material with about 4.3% organic carbon (12). Some 74% of the fresh uncompacted spent shale is 4.76 mm to 25.4mm particle size. Uncompacted dry bulk density is 977 kg/cu. meter (61 lbs/cu.ft.), and its field moisture content is 16%. The shale can be compacted to a density of 1440 kg/cu. meter (90 lbs/cu.ft.) in a disposal pile. Typical chemical composition of the ash is shown in Table 3-14.

Table 3-15 below lists some typical values for densities, sizes, and porosities of carbonaceous and burned retorted shales before compaction.

Table 3-15. Properties of Retorted Shales (27)

	TOSCO II	GCR
Geometric mean size, cm	0.007	0.205
Bulk Density, g/cm^3	1.3	1.44
Solids Density, g/cm^3	2.49	2.46
Porosity (fraction)	0.47	0.41
Permeability, cm^2	2.5×10^{-10}	3.46×10^{-9}

Tests on field plots consisting of TOSCO II (and GCR) retorted shales have indicated that in place compaction densities of about 880 kg/m^3 (55 lbs/ft^3) can be attained, and surface compaction densities as high as 1620 kg/m^3 (101 lbs/ft^3) are possible (26).

Retorted shale from the Superior process will have different properties than retorted shales from other processes. The raw oil shale found in deep deposits of the Northern Piceance Basin contains sodium and aluminum minerals, and these are slated for recovery along with pyrolysis products by the Superior Oil Company. Superior retorted and processed shale may be partially "burned," depending on the mode of operation, and will have been stripped of most of the soluble sodium and aluminum salts. Little is known at present about the detailed physical and chemical properties of such processed shales.

Soluble Salts Associated with Burned and Carbonaceous Retorted Shales: Processed shales contain mineral components which may be partially dissolved by water. Laboratory and field experiments have shown that sodium, calcium, magnesium, potassium, bicarbonate, sulfate, and chloride are present in waters which have contacted freshly processed shale (27). Table 3-16 presents results of laboratory leaching experiments of raw and retorted shales. TOSCO II and USBM retorted shale each contain about 10 kg/tonnes (20 lbs/ton) of readily leachable salts, roughly ten times that leachable from raw oil shale. Data for the burned shale from the Union A process (column 4 in Table 3-16) indicates that total soluble salts depend heavily upon extent of carbon burnoff and mineral decomposition which occur in the combustion zone of a GCR.

The rate and extent of soluble inorganic salt leaching of retorted shale which will occur under field conditions depends on a number of factors in addition to the type of retorting process employed. Such factors include the amount of water added, the degree of compaction accomplished, the manner in which a pile is laid down (eg, slope, depth of pile), the extent of pre-leaching which is accomplished in connection with revegetation, and the age or weathered state of the shale pile. Also, burned shales can form partially cemented barriers to water within a disposal pile which can serve to inhibit further leaching.

Table 3-16. Inorganic Ions Leachable from Freshly Retorted Shales (kgs/tonne) - Based on Laboratory Tests (27)

Ion	Raw Shale	TOSCO II	GCR (USBM)	GCR (Union A)
K^+	0.24	0.32	0.72	6.25
Na^+	0.48	1.65	2.25	21.0
Ca^{++}	0.1	1.15	0.42	3.27
Mg^{++}	0.01	0.27	0.[illegible]	0.91
HCO_3^-	0.75	0.20	0.38	0.28
Cl^-	0.22	0.08	0.13	0.33
$SO_4^=$	0.79	7.3	6.0	62.3
Total (kg/tonne)	1.96	10.96	9.94	94.34
(lbs/ton)	(3.9)	(22)	(20)	(188)

Organic Substances in Retorted Shale: The carbonaceous component of processed shales contains organic substances which can be extracted by organic solvents (ie, benzene), and by water. From .01 to .1% by weight of processed shales are benzene soluble, and substances such as phenols, aromatic acids, and amines are present in the soluble fraction. Compounds belonging to the POM class are also present in benzene extracts, including the suspected carcinogen benzo(a) pyrene (BaP) (16). Recent experiments have indicated that POM and other organics can be extracted by water, along with inorganic salts. Further, process water to be used for moisturizing retorted shale prior to disposal contains similar organic substances (Tables 3-12 and 3-13), some of which may be subject to later removal by water running off of or percolating through disposal piles.

Benzo(a) pyrene (BaP) is a readily measurable member of the POM class of compounds. Commonly, BaP is used as an indicator compound for potential carcinogenicity of materials in which it is found. Table 3-17 lists some BaP levels in some natural and industrial materials. Carbonaceous retorted shales contain BaP in concentrations similar to those found in many natural organic materials (28). Shale oils, in contrast, contain relatively high levels of BaP. The values shown in Table 3-17 do not necessarily indicate the bioavailability of BaP in individual materials, nor do they reflect the presence of other potentially carcinogenic substances.

Retorted shales have also been tested for carcinogenic properties using test animals (28). Although benzene extracts of carbonaceous retorted shale exhibit carcinogenic activity on the skins of mice, retorted shale itself has not shown such skin activity in mice exposed to the shale as bedding in long term experiments. Further conclusions with respect to effects of retorted shale on internal organs of test animals cannot be made at this time, pending the results of pathological tests currently underway. POM extracted from retorted shale by water may be somewhat more active as an animal skin carcinogen than retorted shale itself (16).

3.3.3 Other Shale Derived Solid Wastes

Retorting and on-site shale oil upgrading can result in the production of shale derived wastes such as coke and oily sludges.

Shale Oil Coke: If the crude shale oil produced by retorting is upgraded on site prior to shipment to market, a possible product is coke. This coke must be stored prior to sale or will require disposal as a waste. Shale oil coke is expected to have the typical composition shown in Table 3-18. Storage or disposal piles must provide for non-leaching of soluble salts and organic substances to the environment.

API Separator Sludges: Oily and tarry material separated from wastewaters may constitute a semi-solid waste requiring disposal. Such material may contain suspended solids, hazardous organics, and trace elements. Handling options include (1) burial with other solid wastes in the processed shale pile, (2) incineration with air pollution control, and (3) reinjection into the retort or upgrading units.

3.3.4 Non-Shale Solid Wastes

If substantial upgrading operations are conducted at or near the retorting site, non-shale solid wastes will be generated which require disposal. Such wastes include spent catalysts from hydrotreating, sulfur recovery, and arsenic removal operations, lime sludges and other solids from water and wastewater treatment systems, and spent carbon and diatomaceous earth from gas and oil treating units. Some of these wastes may contain highly toxic substances such as arsenic, and/or may result in emission of hazardous

Table 3-17. Levels of Benzo(a)pyrene (BaP) Reported in Selected Natural and Industrial Materials (28)

Substrate Material	Benzo(a)pyrene (parts per billion)
Natural Materials	
Coconut oil	43.7
Peanut oil	1.9
Oysters (Norfolk, Va.)	10 to 20 (based on dry weight)
Forest soil	4 to 8
Farm field near Moscow	79
Oak leaves	300 max
Petroleums and Petroleum Products	
Libyan crude oil	1,320
Cracked residuum (API Smpl 59)	50,000
Cracked sidestream (API Smpl 2)	2,000
West Texas paraffin distillate	3,000
Asphalt	1×10^4 to 1×10^5
Oil Shale Related Materials	
TOSCO II retorted shale	13 - 100
BCR retorted shale	15
Raw shale oil (Colorado)	30,000 - 40,000
Crude shale oil (TOSCO II)	3,130
Hydrotreated shale oil (0.25%N)	6,900
Hydrotreated shale oil (0.05%N)	690
Coals	
High volatile bituminous	4,200
Low volatile bituminous	3,150
Lignite	1,200
Coal tar	3×10^6 to 8×10^6

materials during their handling, disposal or reprocessing. Hydrodenitrification catalysts for example, may contain 10-13% carbon, 8-10% sulfur, and up to 7% arsenic after their useful activity has been exhausted and regeneration or disposal is required (2).

Table 3-18. Typical Composition of Shale Oil Coke

	(1)	(2)
Ash, wt %	10-15	12.6
Moisture, wt %	7.0	N/A
Carbon, wt %	91	82.5
Hydrogen, wt %	3.6	
Oxygen, wt %	1.3	
Total Nitrogen, wt %	3.9	4.1
Sulfur, wt %	0.5	0.8
Arsenic, ppm	5-10 (0.3 water soluble)	N/A

(1) U.S. Energy Outlook, Appraisal by Oil Shale Task Group, National Petroleum Council, 1972, data are for shale oil produced by TOSCO II retorting (Ref. 29).

(2) Detailed Development Plan, Lease Tract Ca, data are for combination Paraho and TOSCO II produced shale oil (Ref. 7).

3.3.5 Inventory of Solid Wastes

The anticipated quantities of solid wastes to be produced by example retorting processes, to the extent that these are presently known or predictable, are discussed below.

TOSCO II - Colony Development Operation (3): A complete inventory of the solid wastes from commercial shale oil production has been compiled by Colony for the TOSCO II process, and is shown in Table 3-19. The basis is a plant processing 55,000 tonnes (61,000 tons) of raw shale daily, and producing an average of 50,000 tonnes per day (18.3 million tonnes/year) of waste for disposal. Some 97% of this waste, or 48,300 tonnes (53,300 tons) per day, is processed shale (and processed dust). An additional 385 tonnes (425 tons) per day is raw shale dust. The remaining wastes are spent catalyst materials, sludges, arsenic-laden solids, processed plant sanitary wastes, and 725 tonnes/day (800 tons/day) of coke.

These wastes (except for the coke) are to be transported by closed conveyor to a disposal site in Davis Gulch (north of the plant site at Parachute Creek, Colorado), transferred to trucks for distribution in a processed shale/

plant wastes embankment-type landfill, and compacted to 1,360 kg/cubic meter (85 lbs/cu.ft.).

Paraho - Anvil Points (5,21): The present Paraho lease on the Naval Oil Shale Reserve provides for the processing of a maximum of 362,000 tonnes (400,000 tons) of mined shale over a 5-year period. This could produce up to 308,000 tonnes (350,000 tons) of processed shale and other plant wastes from the pilot plant and semi-works operations currently in progress, over the 5-year lease period. These modest quantities can be disposed of by Paraho at the existing (USBM plant) dump site, or the new test site being created by Paraho.

When the single, full-size modular retort is constructed it will have a nominal capacity of 11,800 tonnes (13,000 tons) per day of raw shale, and produce approximately 8,800 tonnes (9,700 tons) per day of spent shale, plus an additional 520 tonnes (570 tons) per day of raw shale crushing fines; or 9,300 tonnes (10,200 tons) per day of waste. This is equivalent to up to 3.4 million tonnes of waste per year.

There is authorization for the processing of as much as 10 million tonnes of raw shale through the modular retort. However, it is expected that closer to 3.6 million tonnes (4 million tons) will be processed over the expected 30 months of operation of the modular unit, thus producing a total of 3.25 million tonnes (3.6 million tons) of total waste from the modular plant. It is planned that these wastes will be conveyed to the present Paraho, canyon-disposal site, compacted, contoured, and revegetated.

Lease Tracts: The quantities of solid wastes produced at Tract C-b will be similar to those listed in Table 3-19, since retorting and upgrading operations at that tract are similar to operations proposed by Colony for the Parachute Creek development. Quantities of solid wastes associated with operations at lease tract C-a will be somewhat larger than those at C-b on a unit product basis, since a lower average grade of shale will be processed, and overburden and sub-ore from open pit mining will require disposal. Non-shale solid wastes at C-a are expected to be of similar magnitude and composition to those reported in Table 3-19. Estimated quantities of solid wastes for Phase IV operations at tracts U-a/U-b are listed in Table 3-20 (23).

Table 3-19. Major Solid Wastes from TOSCO II Processing (2)
(Based upon processing 55,000 tonnes of raw shale per day)

Source of Solid Waste	Approximate Quantity	Annual Production (tonnes)	Major Constituent
Pyrolysis Unit			
Processed Shale	48,400 T/D*	17,650,000 T	Processed Shale
Clarifier Sludge from Wet Scrubbers-Preheat System	780 T/D*	285,000 T	Raw Shale Dust
Ball Circulation System	59 T/D*	21,570 T	Processed Shale Dust
Processed Shale Moisturizing System	39 T/D*	14,266 T	Processed Shale Dust
Total	49,200 T/D		
Crushing Unit			
Primary Crusher	23 T/D	8,300 T	Raw Shale Dust
Final Crusher	295 T/D	107,600 T	Raw Shale Dust
Shale Storage Silo	68 T/D	24,900 T	Raw Shale Dust
Total	386 T/D		
Upgrading Units (Hydrotreaters)			
Naphtha	0-68 T/2 yrs (max)	0-34 T	Spent HDN Catalyst
Naphtha	55 T/yr	55 T	Proprietary Solid
Gas Oil	0-236 T/2 yrs (max)	0-118 T	Spent HDN Catalyst
Gas Oil	318-432 T/yr	318-432 T	Proprietary Solid
Hydrogen Unit			
Hydrodesulfurizer	123 T/3-5 yrs	31 T	Spent HDS Catalyst
Caustic Wash	2.2 T/D	800 T	Spent Aqueous Caustic
Guard Bed	14 T/1-3 yrs	6 T	Spent ZnS Catalyst
Shift Converter (High Temp.)	45 T/5 yrs	9 T	Spent Fe-Cr Catalyst
Shift Converter (Low Temp.)	45 T/3 yrs	15 T	Spent Cu-Zn Catalyst
Sulfur Unit			
Claus Unit	136 T/2 yrs	68 T	Spent Bauxite Catalyst
Tail Gas Hydrotreater	9 T/5 yrs	2 T	Spent Co, Ni-Mo Catalyst
Gas Treating Unit			
DEA Filter	7.5 T/2 weeks	190 T	Diatomaceous Earth
DEA Filter	7.5 T/2 weeks	390 T	Deactivated Carbon
Coker Unit	727 T/D	265,000 T	Green Coke
Water Treatment	0.5 T/D .02 T/D	200 T 8 T	Lime & Alum Flocculants Proprietary Coagulant Aid

T/D = tonnes/day

*Water Excluded

Table 3-20. Solid Wastes Generated During Construction and Operation of Shale Oil Facilities at Tracts U-a/U-b - Phase IV (16,000 m^3 shale oil/day) (23)

Source of Waste	Quantity
Retort Shale (dry basis)	118,000 tonnes/day
Raw Shale Fines	755 tonnes/day
Spent Catalysts	1550 tonnes/year
Waste Fire Brick and Fines Type Heat Carrier	640 tonnes/year
Diatomaceous Earth and Activated Carbon	90 tonnes/year
Elemental Sulfur	80 tonnes/day
Construction Wastes	27,000 tonnes (total)

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4.0 POTENTIAL IMPACTS OF EXTRACTION AND PROCESSING ACTIVITIES ON THE PHYSICAL ENVIRONMENT

Assessment of the potential environmental impacts of oil shale development is the central issue to be addressed by this chapter. The assessment includes a description of the baseline environmental conditions and a review of the environmental impact studies performed to date by the various developers and organizations. The air quality section includes a discussion of the existing meteorology and air quality in and around potential development sites, and a review of modeling studies which have been undertaken to predict air quality impacts. The discussion of the impacts on water quality and hydrology includes descriptions of existing surface and ground water quality and yields, the relationship of ground and surface waters in the development areas, the effects of the consumptive use of water, and the potential effects of wastewater disposal practices on surface and ground waters. Spent shale and solid waste disposal plans are summarized, including descriptions of the physical settings of proposed disposal sites and an identification of potential hazards and pollution problems.

4.1 AIR QUALITY IMPACTS OF OIL SHALE EXTRACTION AND PROCESSING

This section includes a baseline characterization of the air quality and meteorology of the Piceance Creek and Uinta Basin areas, and a review and evaluation of modeling efforts undertaken to predict the impact of oil shale mining and processing activities on ambient air quality.

4.1.1 Baseline Characterization of Meteorology and Air Quality

The size of the region, its sparse population and its topography will all have a strong effect on the meteorology and ambient air quality of the region.

Meteorology: At the present meteorological data are not available for every potential oil shale site; measurements are only now being made at certain sites. Meteorological measurements are currently available for the Parachute Creek Valley and Roan Plateau of Western Colorado as well as for the Piceance Creek Basin. Parachute Creek Valley and Roan Plateau data have been taken by Dames and Moore and by Battelle Northwest Laboratories under contract to the Colony Development Operation (1). Piceance Creek Basin data have been taken by the Rio Blanco Oil Shale Project (2). Data and information from these two sources will be used to illustrate those features which are especially important to the transport and dispersion of pollutants in the atmosphere.

In general, sunshine prevails over the region, and precipitation and relative humidity are low. Precipitation is highest during the winter, and occurs in the form of snow at high altitude terrain and in the form of rain at lower altitudes. Temperatures generally range between -40° to 100°F in the lower regions.

Surface winds are variable with strong spatial, diurnal and seasonal dependence, as to be expected, with the prevailing wind in the region being southwesterly. In Parachute Creek, Colorado River Valley and White River Valley little information is available on air stagnation, but studies at nearby Grand Junction show the region to have one of the highest frequency of inversions anywhere in the United States (14).

Topography has an important influence on local meteorology. The presence of rugged terrain causes turbulence within the planetary boundary layer (3). This favors high dilutions which have, in fact, been observed (4,5). Topography especially influences the mountain-valley systems, resulting in differential heating and cooling. In the presenceof radiational cooling at night, as would occur under clear skies, a drainage circulation is often set up in which flow occurs down the side of a mountain or down a slope. During the daytime, the direction is reversed and flow becomes up-slope or up-valley. This system is commonly referred to as the mountain-valley breeze system. From an air pollution standpoint, this is a very important system in the oil shale,region (6).

The mountain-valley systems are typically weak, local circulations, with the drainage flows characteristically weaker than the up-slope flows. Even at peak intensities, velocities seldom are greater than a few meters per second. Both up-slope and down-slope flows tend to be confined near the ground surface, being around 100m thick and only seldom thicker than 200m. (The foregoing estimates represent drainage flow thicknesses in other regions at latitudes similar to the oil shale region. At the time of preparation of this report no detailed drainage data were available for the study region.) A drainage flow initiated at the top of a slope starts out very shallow and gradually thickens as the air mass flows downhill. An up-slope flow shows a similar thickness variation, being shallow at the base of the slope and thickest at the top. These flows are very local and, in general, are not strongly coupled to the mean flow within the Ekman layer.*

There are other types of air flows which owe their origin to the combined effects of meteorology and topography. These, conceivably, may have a deleterious effect on air quality. One special flow can occur when a plume, emitted close to the base of a stable layer, encounters a highly unstable lower layer. In this case, rapid mixing takes place, potentially producing high levels of ground concentration (fumigation) which may be intensified by the presence of elevated terrain. However, like other special flows (fanning, coning, lofting and looping), fumigation requires the right set of conditions of atmospheric turbulence structure and plume emissions.

To summarize, limited meteorological measurements have been made for the oil shale region, and site specific information is generally lacking except for the lease tracts. In another year or two more data may become available

*That part of the lower atmosphere in which surface induced stress decreases with height, the Ekman layer usually extends to between 100 and 1000 meters above ground level.

from on-going baseline measurement programs. The data which are now available show prevailing winds to be from the southwest, and inversions to occur frequently at Grand Junction. Local flows are characterized by the mountain-valley breeze systems. A plume emitted within the drainage flow of such a system may lead to elevated concentrations at downwind receptors along the valley floor. Other special flows such as fumigation may also pose a problem but these require the right combination of turbulence conditions and emissions. The most important circulation influence on ground level concentrations is probably the drainage flows.

Air Quality: At present, there are very few anthropogenic emissions in the oil shale region. Nevertheless, ambient levels of air pollution exceed some state and federal standards. Measurements taken to date at Tracts U-a and U-b in the Uinta Basin (21), show that ozone and nonmethane hydrocarbon sometimes exceed the primary National Ambient Air Quality Standards (NAAQS). However, the levels of most other pollutants are usually below the limits of detection of common air monitoring instruments. At tracts C-a and C-b, particulates, ozone and nonmethane hydrocarbons (NMHC) currently exceed NAAQS. The most recent data (see Table 4-1) collected at Tracts C-a and C-b show that the 24-hour primary particulate standard was exceeded between 4 to 5 times, the one hour oxidant standard was exceeded 5 times and the 6-9 am NMHC standard was exceeded 94 times.

At Tracts C-a and C-b in the Piceance Creek Basin, the air quality is generally similar to that in the Uinta Basin (Table 4-1). Based on periodic measurements taken over several years (1) in the Piceance Creek Basin total suspended particulates average 15μg per m^3 annually, NO_2 averages 7μg per m^3 annually, and SO_2 less than 20μg per m^3. These values are much lower than the NAAQS (annual average of 75μg per m^3 for particulates, 100μg per m^3 for NO_2, and 80μg per m^3 for SO_2). Hydrocarbon concentrations show seasonal fluctuations with a maximum during the growing season. Tracts U-a and U-b show similar annual averages: 22 μg per m^3 for TSP, 10 μg per m^3 for NO_2 and 10 μg per m^3 for SO_2.

A significant amount of haze has been observed in Parachute Creek Basin and along the Colorado River Valley (2,17). The origin of this haze is unknown at the present, but four mechanisms of formation have been suggested. First, in both the Piceance Creek and Uinta Basins, relatively high levels of nonmethane hydrocarbons have been observed. These have been attributed to natural sources such as sagebrush and other vegetation. Hydrocarbon and the NO_2 concentrations (low though they are) could contribute significantly to the high photochemical oxidant values which are sometimes observed in the Uinta Basin. The photochemical process, if it involves the O_3-NO_2 cycle, may be accompanied by visibility degradation. Second, under high relative humidity (50%) particulates in the air could serve as condensation nuclei which can grow by heterogeneous nucleation into "visible" sizes of a few microns. The light scattering of such "mixed" aerosols could explain the haze observed. Third, long range transport of anthropogenic hydrocarbons and NO_x, potential percursors of oxidant (and haze), is also possible. Fourth, the intrusion of stratospheric ozone into the lower troposphere is also a possibility especially at mid latitudes where there is a break in the tropopause.

Table 4-1. Existing Air Quality Data Summary for Federal Oil Shale Lease Tracts (2,17,21)

Criteria Pollutant	Primary National Standard	Tract C-a	Tract C-b	Tracts Ua-Ub
Particulate				
Maximum 24 hour (μg/m^3)	150	469	178	127
Annual mean (μg/m^3)	75	18	11	22
No. occurrences exceeding NAAQS*		5	4	
SO_2				
Maximum 3 hour (μg/m^3)	1,300	345	88	40
Maximum 24 hour (μg/m^3)	365	82	43	25
Annual mean (μg/m^3)	80	19	1	10
NO_x				
Annual mean (ug/m^3)	100***	4	10	10
CO				
Maximum 1 hour (μg/m^3)	40,000	6,823	2,841	5,200
Maximum 8 hour (μg/m^3)	10,000	4,824	1,669	3,900
NMHC**				
Maximum 3 hour (ug/m^3)	160	505	2,316	1,970
No. occurrences exceeding NAAQS*		94		138
Oxidant				
Maximum 1 hour (μg/m^3)	160	177	160	190
No. occurrences exceeding NAAQS*		5		42

*National Ambient Air Quality Standards

**Nonmethane hydrocarbons

***Standard applies to NO_2

4.1.2 Review of Model Application to Oil Shale Related Emissions in Colorado and Utah

Recently, several modeling efforts have been undertaken to predict the impacts that oil shale mining and processing might have on ambient air quality. The modeling concept most widely used in these studies has been the Gaussian model which is described in several standard references(7,8,9). In this model, the basic equation describing concentration, X, from a continuous emissions source at effective stack height, H, is given by:

$$X = \frac{Q}{2\pi\sigma_y\sigma_z U} \exp\left[-\frac{1}{2}\left(\frac{y}{\sigma_y}\right)^2\right]\left\{\exp\left[-\frac{1}{2}\left(\frac{z-H}{\sigma_z}\right)^2\right] + \exp\left[-\frac{1}{2}\left(\frac{z+H}{\sigma_z}\right)^2\right]\right\} \quad (4\text{-}1)$$

where Q is the emissions rate, σ_y and σ_z the standard deviation of the plume distribution in the horizontal and vertical respectively, U the mean wind speed, y the horizontal coordinate distance reckoned from the plume centerline, and z the vertical coordinate distance reckoned from ground level.

The effective stack height, H, is related to the actual stack height, h, by

$$H = h + \Delta H \quad (4\text{-}2)$$

where ΔH is commonly referred to as the plume rise height. Several methods (10,11) have been developed to estimate this quantity. Typically, H depends on stack parameters (effluent velocity and temperature, and stack radius), and environmental conditions (atmospheric lapse rate of potential temperature and temperature differential between plume and environment). The plume rise formulation has long been a source of controversy, and the matter is still not settled to the satisfaction of all.

Application of diffusion modeling must be done with all due care. The problem being modeled is often times complex and requires simplifying assumptions in order to make the problem tractable. Uncertainties are frequently associated with the source input data (meteorology and emissions). These simplifying assumptions and uncertainties have led to the commonly held view that "most model results are generally good to within a factor of two."

Battelle, Northwest Laboratories, conducted one of the earliest oil shale modeling studies (12) for the Colony Development Operation. A model was applied to a typical oil shale plant situated in the Parachute Creek Valley and to Roan Plateau using diffusion data collected by Battelle and meteorological data provided by Dames and Moore. Engineering Science, Inc. has also conducted a study (13) of the Piceance Creek Basin for the Federal Energy Administration to assess the air pollution potential of future oil shale development. Stanford Research Institute completed a similar study (14) for the U.S. Environmental Protection Agency, but with the emphasis on controls. Most recently, three other studies have been completed: Detailed Development Plan (DDP) for Tract C-b submitted by the C-b Shale Oil Project (Roxana), DDP for Tract C-a submitted by the Rio Blanco Oil Shale Project, and the DDP for tracts U-a/U-b submitted by the White River Oil Shale Project (2,17,21).

Battelle's Study of Parachute Creek and the Roan Plateau:(12) In the modeling study of the Colony Development Operation in the Parachute Creek Valley and on the Roan Plateau, Battelle used the exact form of the equation shown earlier in equation 4-1. The standard deviations in plume distribution σ_y and σ_z, were expressed in terms of observables, such as standard deviations in anemometer and propeller wind vane fluctuations following methods developed by others (8,15). Buoyant plume rise was formulated after a method developed by Hanna (11).

The wind speed input for equation 4-1 was obtained from a 60m tower measurement, while temperature and potential temperature lapse rates were obtained from the Grand Junction radiosonde data. Total peak emissions for an 8000 m^3/day TOSCO II plant (in kg per hour) were assumed to be: 65 SO_2, 332 NO_x, 136 THC (total hydrocarbons), and 583 PM (particulate matter).

The model was applied to a potential site in the Parachute Creek Valley, and to another on the Roan Plateau. Model results indicate that for the Valley site, NO_2 concentrations will exceed NAAQS while SO_2 and particulate concentrations will be just under standards. THC levels will be considerably under NAAQS. For the plateau site, all concentrations are predicted to be an order of magnitude less. Based on these results, Battelle recommended that the proposed oil shale plant be located on Roan Plateau instead of in the Valley.

Stanford Research Institute's Study of the Piceance Creek and Uinta Basins (14) In a study to assess oil shale air pollution impact in the Piceance Creek and Uinta Basins, SRI used the Climatological Dispersion Model (CDM). Topographic effects were recognized as a potential influence, but were not incorporated in the model. Pollutants treated were SO_2, THC and NO_x. Averaging times selected were those corresponding to air quality standards.

Meteorological inputs were obtained from observations at Grand Junction, Colorado, for the Piceance Basin simulation and from Salt Lake City, Utah, for the Uinta Basin simulation. For the worst case conditions, a meteorological regime comprised of neutral atmospheric stability and a light wind of 1.5m sec^{-1} was assumed. Such conditions are found to persist over 24 hour periods in the oil shale region and occur an average of 15 days/year.

In the actual modeling exercise the emissions from a 16,000 m^3/day (or 100,000 barrels/day) TOSCO II type plant, assumed to be equipped with best controls, were in kg per hour: SO_2 1400, NO_x 1850, THC 272, and PM 295. Following the recommendation of the Battelle study (12), SRI assumed that the proposed plant would be located on a plateau. The results of the modeling exercise show that a TOSCO II type plant equipped with best available controls will not violate the federal ambient air quality standards for criteria pollutants.

Under more stringent ambient air quality standards, such as those proposed for a Class II region, (which seek to prevent significant deterioration of ambient air quality in unpolluted areas) additional controls will be required. To meet the 24-hour particulate standard, 85% additional control will be required;while the annual average SO_2 standard can only be met with 72% additional control. No additional controls are required for hydrocarbons and oxides of nitrogen.

SRI evaluated control technology for the Colony Development Operation (TOSCO II type plant) and concluded that when best-available controls (cyclones, baghouses and wet scrubbers) are employed, particulates and sulfur oxide emissions can be reduced to one-third of the levels previously calculated by Colony.

Federal Energy Administration Study (Piceance Creek Basin) (13): Modeling of air pollution levels associated with oil shale development was conducted by Engineering Science, Inc. under contract to the Federal Energy Administration. Three separate models were used in determining ground level concentrations: up-valley wind model, gradient wind model and a fumigation model. All of these models are Gaussian in nature. The up-valley model, APMAX, was used to calculate short-term concentrations (3-10 minutes) which were then extended to 1-hour averages using an empirical expression. The gradient wind model, APSIM, was used to simulate annual averages by incorporating the wind flow pattern and a stability frequency distribution function. In the fumigation model, it was assumed that the plume would move down the valley at night with the drainage flow and would be contained in a stable layer above the valley floor. Then, with solar heating in the morning, the ground-based inversion would be eroded upwards to the plume layer; whereupon, the plume would mix within the ground-based layer to produce elevated ground level concentrations (fumigation).

Emissions data were obtained from the developers and operators of the proposed oil shale plants, from the Department of Interior, from the Environmental Protection Agency emission factors, and from estimates by contractors. Total emissions, in kg per hour, at a proposed plant site (TOSCO II process at 8000 m^3/day) were: 604 SO_2, 664 NO_x, 144 THC, and 336 PM. Meteorological data were obtained from the Atomic Energy Commission, Department of Commerce, and Colony Development Operation. However, available meteorological data were not adequate for defining important diffusion parameters in the Piceance Creek Basin. Engineering Science, Inc., therefore, synthesized a wind-flow pattern and frequency distribution for use in calculating dilution and dispersion of released air contaminants.

The study evaluated the primary pollutants - SO_2, NO_x, THC and PM. It was found that under the Accelerated Development (which would produce up to 200,000 m^3/day during the period 1980-1990), the primary and secondary standards for SO_2 as well as those promulgated for particulate matter and nitrogen oxides would be met. However, if the Colorado SO_2 annual standard* of 10 μg/m^3 were implemented, then a production limit of 32,000 m^3/day would be required unless more stringent emission controls could be employed. The proposed EPA Class II incremental limits for SO_2 and particulate matter will result in a production limit of 56,000 m^3 per day without better emission controls.

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*This standard has since been changed to 15 μg/m^3.

The FEA study also considered a hypothetical plant based on Union A processing technology. But the results are not reviewed here because Union B technology, on which current plans are based, has emissions different in nature and magnitudu than those associated with Union A technology.

Colony Development Operation: The Colony Development Operation study (1) used the modeling methods of the Battelle study (12) but with revised emissions estimates. Average emissions for normal emissions, in kg per hour, were: 128 SO_2; 819 NO_x; 147 THC and 376 PM; peak emissions were calculated to be 144 SO_2; 792 NO_x; 138 THC and 392 PM.

The results of the study indicate that the proposed Parachute Valley plant can cause an increase in concentrations (above background values) of 14% SO_2, 0.01% HC, 25-100% NO_x and 3-6% particulate matter. Higher ambient concentrations may occur during plant start-up or during abnormal operating conditions.

Predicted annual mean concentrations due to plant emissions will not exceed Colorado's ambient air quality standards. The twenty-four hour SO_2 concentration may, however, exceed the State's short term concentration of 15μg per m^3 (24-hour average, not to be exceeded more than once in a 12-month period). Also, the 24-hour predictions of 171 μg per m^3 particulates (see Table 4-3) will exceed the national secondary standard of 150 μg per m^3.

C-b DDP (2): The Detailed Development Plan submitted by the lessees of C-b lacks the details necessary to make a proper assessment as to the adequacy of the modeling effort. However, the following information has been provided. A Gaussian plume model was used to estimate concentration of SO_2, NO_x, THC and PM. Average meteorology was used, and the Brigg's (10) method was used for treating plume rise.

Emissions assumed, in kg per hour, were: 121-160 SO_2, 741-859 NO_x, 119-142 THC, and 362-439 PM. The results of the study indicate that plant operations will result in maximum increments over a 24-hour period of 9μg per m^3 SO_2, 34μg per m^3 NO_x, 5μg per m^3 THC and 19μg per m^3 PM. The authors of the DDP concluded that based on the limited study "the best estimate is that compliance with federal and state standards is achievable," and indicated that in Phase II of the modeling study, "the entire modeling process is to be repeated in more depth."

EPA, in a review of the DDP (16), identified three areas of deficiency: too few details with respect to all pollution emissions and controls, inadequate modeling exercise, and the neglect of "fugitive" emissions. In attempting to provide guidance to C-b, the EPA ran their C7M3D model which includes topographic effects, using Colony emissions data. The results indicated that "state and federal air quality standards are predicted to be violated." The developers of tract C-b are presently re-evaluating emissions control and are doing further "worst-case' modeling.

Tract C-a DDP (17): The EPA Valley model (CBM3D) was used for simulating air quality, with modification as necessary for making short-term (3-hour and

24-hour) predictions. Plume rise was treated by Brigg's method (10). Emissions for two phases of operations were considered. It was assumed that Phase I operations will begin in 1979 with a small open-pit mine and a single TOSCO II retort capable of processing 10,000 tonnes of oil shale per day and producing approximately 720 m^3 of pipelinable shale oil daily. It was further assumed that by 1982 this capacity would be doubled to 1440 m^3 per stream day. Phase II operations were assumed to begin by mid-1985, with a total processing capability of 108,000 tonnes per stream day. Delayed coking and hydrotreating is to be employed to produce upgraded shale oil at the rate of 8,982 m^3 per stream day. Emissions, in kg per hour, for Phase I were: 12 SO_2, 146 NO_x, 51 NMHC and 67 PM; and for Phase II: 120 SO_2, 451 NO_x, 84 NMHC and 260 PM.

Modeling results indicate that Phase I operations will meet the NAAQS and state standards for all criteria pollutants, except nonmethane hydrocarbons. The impacts of Phase II operations were found to be similar to Phase I, except that the short-term ambient standards set by the State of Colorado would be violated unless the area were classified Category II.

Ambient air quality was also simulated under fumigation conditions using a multiple-source adaptation of the fumigation model (19). The predicted air quality under these conditions was less severely affected than previously described primarily because baseline monitoring has indicated fumigation to be a transitory state (1 hour duration).

Tracts U-a/U-b (51): Two models were used for simulating air quality at Tracts U-a and U-b. Short term (24 hours and less) concentrations were simulated with EPA's PTMTP model while long term predictions were made with EPA's COM3D "Terrain" model. In the PTMTP application, 10 minute averages were calculated and extended over longer averaging times (up to 24 hours) using statistical concepts developed by Larsen (52). The "Terrain" model assumed as inputs the actual terrain features in the vicinity of the proposed plant site. Both model applications were conservative in their choice of meteorology, emissions, stack height and other parameters so that predictions would represent worse case conditions.

Detailed modeling was done for Phase IV type operations (100,000 barrels per day of raw shale oil). Phase IV involves emissions (in kg per hour) of: 134 SO_2, 1242 NO_x, 50 NMHC and 410 PM. Phase III production rate and emissions will be one half those of Phase IV.

The model results indicate that, with the exception of hydrocarbons and particulates, all short-term NAAQS will be met by large margins. Further, the hydrocarbon emissions include those from the fines-type retort preheaters, which may contain as much as 80 percent methane. If this were true, downwind nonmethane hydrocarbon concentration may be as low as 11.8 μg per m^3. Maximum 24-hour particulate levels were found to be 257 μg per m^3 but exceeds the secondary NAAQS 150 μg per m^3. Modeling results predict that all annual NAAQS will be met.

Since ambient levels are directly proportional to emissions, Phase III operations will lead to ambient levels which are roughly one half of those predicted for Phase IV operations.

4.1.3 Assessment of Models and Model Concepts Applied to Oil Shale Emissions

All of the studies reviewed in Section 4.1.2 have utilized the basic Gaussian equation in one form or another. In the simplest of applications(12), ground level concentrations were estimated using meteorological data measured at a tower, and turbulence data collected during special diffusion studies. The most ambitious modeling exercise to date (17) simulated long- and short-term concentrations in the presence of topographic influences using input meteorological data collected during baseline monitoring at tract C-a.

There are, however, several limitations of the Gaussian model. It is known to overestimate ambient concentrations under calm conditions and at long distances from the source, while underestimating near surface levels (19). The overprediction under calm conditions may be attributed to the inverse dependence of concentration on wind speed in equation 4-1 which physically represents the neglect of convective mixing under calm conditions. To overcome this limitation, similarity theory can be applied to the boundary layer (3). In this method the standard deviation in plume distribution (σ_y and σ_z) would be expressed in terms of mean wind speed, ground roughness and heat flux. Such a parameterization would have the effect of removing the u^{-1} dependence (equation 4-1) since this will be coupled with the u dependence in the σ_y and σ_z.

Overestimation at long distances probably reflects the absence of a measure of plume meander in the turbulence parameterization. Plumes traveling over great distances commonly meander along the way, especially in the presence of topography. Such meandering will enhance plume dilution. Underestimation near the ground surface may be due to the mis-application of the Gaussian concept rather than to shortcomings inherent in the concept. It is well known that special meteorological conditions such as fumigation, looping, etc. can cause high concentrations near the ground. Therefore, an acceptable modeling exercise should incorporate such effects.

In its present form the Gaussian concept is difficult to apply to rugged terrain. Such terrain has two effects on air pollution: first, it physically alters air trajectory; and second, it increases the turbulence level. Trajectory effects can take the form of streamline contouring around elevated terrain or the form of down-slope-up-valley flows induced by mountainous terrain. Streamline modifications due to topography are currently handled mechanistically as in the EPA Valley Model (C8M3D). The only convincing method of treating the enhanced turbulence which results from rugged terrain has been direct observation. However, direct measurements are all too often quite expensive and could produce undesirable delays in making environmental assessments.

In addition to the above mentioned limitations of the Gaussian model, several other simplifying assumptions are implicit or explicit in model predictions. In the early model applications upper air data collected at Grand Junction and Salt Lake City were applied to the Piceance Creek and Uinta Basins, respectively. This is a questionable use of data even though they represent upper air measurements (especially over rugged terrain). This problem has been partially remedied by the site-specific measurements taken as part of the on-going baseline monitoring programs. In some models the time averaged wind speed and prevailing wind direction are used. These quantities are assumed to be constant over time. Also, wind measurements taken at one point are frequently used to characterize the flow of the diffusing layer. These represent obvious shortcomings which must be addressed prior to and during model application.

Atmospheric diffusion modeling in general is limited in its ability to handle particulates and reactive (or secondary) pollutants. When applied to particulate emissions, a wide range of particle sizes must be considered. Particles smaller than 20μm may be treated as a gaseous species while the larger ones must recognize gravitational settling as an important removal mechanism. Fugitive dust remains difficult to model for these reasons and also because the emissions themselves depend on meteorology. Secondary pollutants such as photochemical oxidant and aerosols cannot be handled by simple Gaussian models, since formation of such substances in the atmosphere depends on sunlight as well as precursor (and/or catalyst) concentrations.

Finally, all models are useful only to the extent that emissions data are accurate and representative. Differing assumptions regarding emission factors, plant size, sources covered, and normal vs. transient operations can lead to dramatically different predicted concentrations of pollutants.

4.1.4 Comparison of Modeling Results

The emissions (kg per hour) used in the various modeling studies are tabulated in Table 4.2. A comparison of modeling results is difficult because of the different assumptions with respect to processes (TOSCO II, Paraho, etc.), plant configuration and size, and meteorological emissions factors. Certain generalizations may, however, be made. A typical shale oil plant with a production capacity of 6000 m^3 per day can be expected to have an hourly emissions of 100-150 kg SO_2, 400-800 kg NO_x, 80-150 kg THC and 250-400 kg PM.

The Colony Development Operation study used the modeling methods developed by Battelle, but with a different set of emissions (as may be seen in Table 4.2). Of the two, Colony's emissions are the more recent (reported in December 1975 versus October 1973 for the Battelle emissions), and are therefore, more realistic since they incorporate the most recent data. Colony also estimated the average maximum emissions of the proposed shale oil plant for Roan Plateau. These estimates were reported in 1974 (20), and in kg per hour, are 144 SO_2, 792 NO_x, 382 PM and 138 THC.

The summary of the air quality modeling predictions are presented in Table 4-3. Ambient air quality standards for major criteria pollutants are likely to be violated according to the predictions. Sulfur dioxide will meet federal ambient air quality standards at all sites but will exceed the federal significant deterioration standard and Colorado's maximum allowable increments at certain sites.

Table 4-2. A Comparison of Air Pollutant Emissions (kg per hour) Used in Modeling Studies

STUDY	PRODUCTION m^3/day	SO_2 KG per HR	NO_x KG per HR	THC KG per HR	PM KG per HR
Battelle (Parachute Creek and Roan Plateau)	8,000	65	332	136	583
FEA (Piceance Creek Basin)	[illegible],000	604	664	144	336
SRI (Piceance Creek and Uinta Basins)	16,000	1411	1050	272	295
Colony Development Operation (Parachute Creek and Roan Plateau) Normal Peak	10,000	 128 144	 619 752	 147 138	 376 382
C-b DDP (Piceance Basin)	7,200	127-160	741-859	119-142	332-439
C-a DDP (Piceance Basin) Phase I Phase II	 960 6,900	 12 123	 146 457	 51 84	 67 262
U-a/U-b DDP (Uinta Basin) Phase II Phase III*	 1,600 8,000	 3.2 67	 49 621	 0.4 25	 31 205

*Phase IV involves doubling of production and emissions from Phase III at Ua/Ub.

Federal particulate ambient air quality standards are currently exceeded at the lease tracts. Particulate increment increases forecast to occur at these sites will also exceed the federal significant deterioration standards. The measured hydrocarbon levels are currently quite high and occasionally exceed federal 6-9 am standards. Likewise, the forecast levels are also high at all sites.

Although the modeling studies reviewed in this section differ in complexity and assumptions, all studies have predicted that certain ambient air quality standards will be violated if oil shale development occurs. Currently, levels of suspended particulates and non-methane hydrocarbons approach and occasionally exceed short term ambient standards in the oil shale region, and additionally emissions due to oil shale development will worsen the situation. Significant deterioration and incremental increase standards for SO_2 may also be violated. It might be commented that the emissions assumed in some of the modeling exercises do not include sources such as fugitive dust emissions, blasting emissions, and transient releases (such as would occur during plant upset). Although difficult to quantify, these uninventoried contributions to oil shale emissions suggest that the predictions in Table 4-2 are probably underestimates of ambient levels.

Much can still be done to reduce ambient air quality levels resulting from oil shale development and therefore to mitigate the impact on the air environment. Better emissions controls in the future would directly reduce ambient levels. Increased stack heights would provide a thicker diffusing layer for plant effluents; and this, in turn, would lead to lower ground concentrations. Reduced plant size would lead to proportionately lower emissions and therefore, lower ambient concentrations. Plants may be sited on terrain which would favor diffusion and transport. One or more of the above features may be combined to provide even greater reduction in ambient levels.

Table 4-3. Comparison of Modeling Results with Applicable Standards. All Quantities in μg per m^3 (References shown in parentheses)

[illegible]

4.2 IMPACTS ON WATER QUALITY AND HYDROLOGY

Commercial development of Green River oil shale can have impacts on local and regional surface and ground water quality and flows. Diversion of water for consumptive use in the upper Colorado basin can adversely affect the average discharge and quality of water in the lower Colorado basin. Direct and indirect wastewater discharges may degrade local water quality and change the existing hydrologic regime. This chapter includes a review of existing surface and ground water quality and flows in northwestern Colorado and northeastern Utah, a summary of predicted affects of consumptive water use for oil shale development, a summary of water pollution control plans for major developments, and a discussion of potential indirect and accidental sources of water pollution associated with the oil shale extraction, processing, and waste disposal activities.

4.2.1 Existing Surface Water Quality and Flow

The major rivers and streams in the oil shale region are the White River and its tributaries - Piceance and Yellow Creeks, and the Colorado and its tributaries - Roan and Parachute Creeks.

4.2.1.1 Upper Colorado River Basin

The oil shale regions of Colorado and Utah are located in the Upper Colorado River basin and includes all of the drainages of the Colorado River above Lee's Ferry, Arizona and encompasses an area of approximately 50,000 sq. km (19,500 square miles). In the upper basin, 77 percent of the area receives less than 50 cm (20 inches) of precipitation, and 42 percent receives less than 30 cm (12 inches) (22).

Water quality and discharge are monitored by the U.S. Geological Survey at more than 50 stations in the Upper Colorado River basin on the larger tributaries and main stem of the Colorado River. Basic data are published annually for each state. Table 4-4 summarizes discharge and water quality data on the White and Colorado Rivers at location nearest the Colorado and Utah oil shale regions.

4.2.1.2 Piceance Creek Basin

A major east-west trending topographic divide just south of the Rio Blanco-Garfield County line separates the streams draining the Piceance Creek basin into two drainage systems. The northern part of the basin is drained by tributaries of the White River (Piceance and Yellow Creeks). The southern part of the basin is drained by tributaries of the Colorado River (Parachute and Roan Creeks). Figure 4-1 shows the location of proposed oil shale development activities relative to the surface drainage systems.

Streamflow in the Piceance Creek basin is typical of those regions where the main source of water is snowmelt. Starting in March or April, snowmelt produces a period of high runoff that extends to June or July. During the remainder of the year, streamflow is maintained almost entirely by ground water discharge. The surface-water/ground-water systems in the Piceance Creek

Table 4-4. Water and Dissolved Solids Discharge at Selected Stations in Upper Colorado River Basin (22)

Location	Drainage Area (sq.km) (sq.mile)	Average (m^3/min) (cfs)	Annual AF (10^9 m3) (acre-ft)	Dissolved Solids: Weighted Average Concentration (mg/l)	Dissolved Solids: Average Annual Discharge (tonnes/yr) (tons/yr)
White River near Meeker, Colo. (1)	1974 (762)	1060 (638)	0.57 (462,200)	224	139,000 (153,400)
White River near Watson, Utah (2)	10400 (4020)	1300 (764)	0.68 (553,500)	439	300,000 (330,000)
Colorado River near Glenwood Spr., Colo. (loc.off map) (3)	11600 (4486)	4080 (2338)	2.14 (1,738,000)	270	581,000 (639,200)
Colorado River near Cameo, C Colo. (4)	20900 (8060)	4138 (4138)	3.7 (2,998,000)	387	1,430,000 (1,578,000)

( ) See Fig. 4-1 for location

basin are intimately related; ground water discharge accounts for about 80 percent of the volume of stream flow (23).

- Piceance and Yellow Creeks: Flows in Piceance and Yellow Creeks are highly variable and strongly influenced by irrigation practices. Table 4-5 summarizes stream flow records at four locations on Piceance Creek and one location on Yellow Creek. Mean annual discharge of Piceance and Yellow Creeks into the White River is 14,520 and 1,130 acre feet, respectively.

The upper reaches of both Piceance and Yellow Creeks surface waters can be classified as a mixed bicarbonate type, grading to a sodium bicarbonate type in the lower reaches. Concentrations of dissolved solids, sodium, chloride, and fluoride all increase in the downstream direction. In general, water quality is best during periods of high discharge but the chemical character remains about the same. The total dissolved solids (TDS) concentration in Piceance Creek ranges from 440 to 5700 mg/l; the TDS content in Yellow Creek ranges from 1400 to 3000 mg/l (25). The sulfate and dissolved solids concentrations exceed the public water supply limits in the upper reaches of both creeks and water in the lower reaches has fluoride concentrations of more than twice the limit of 1.0 mg/l established by the U.S. Public Health Service (27).

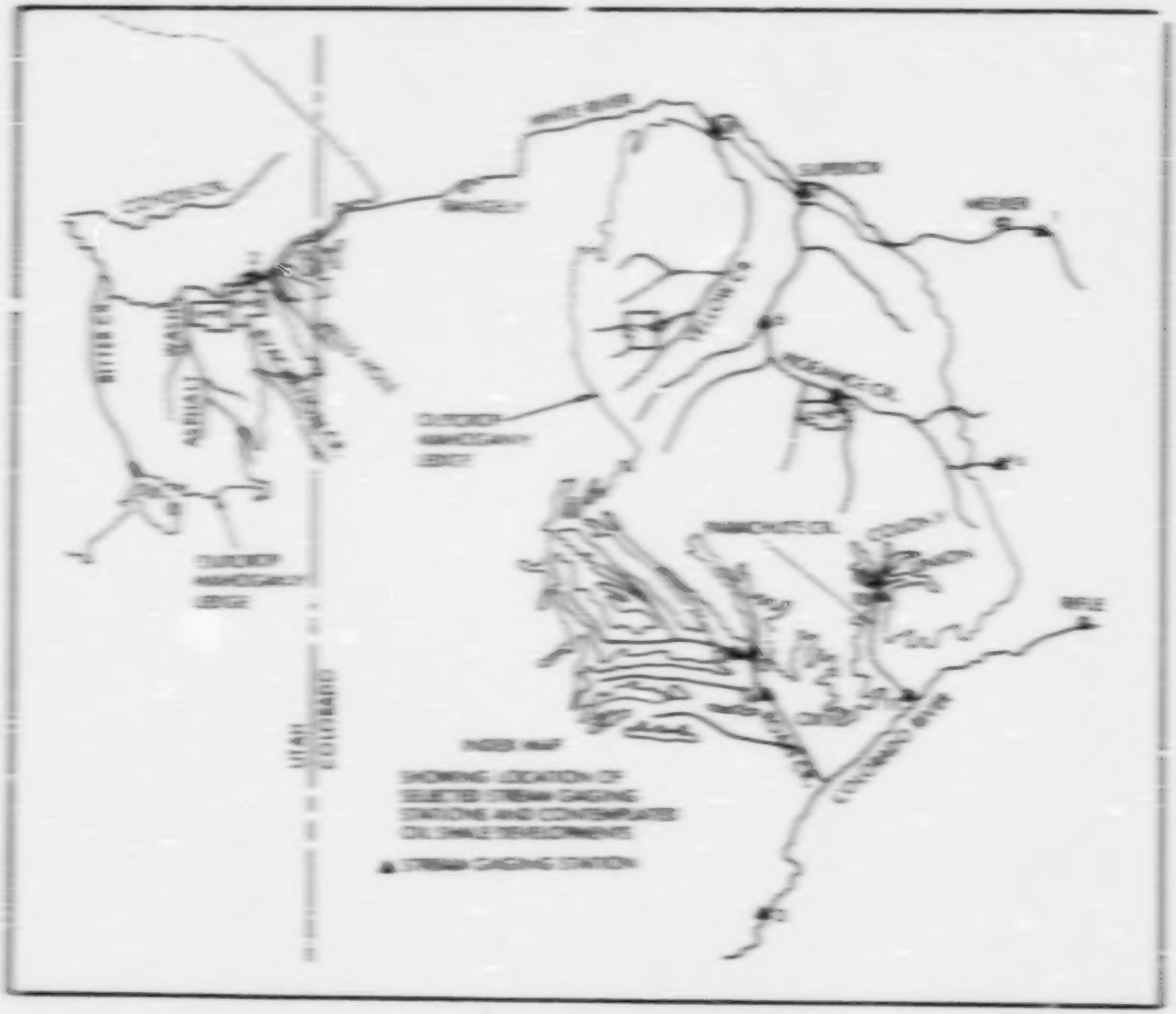
WHITE RIVER
RANGELY
MEEKER
OUTCROP MAHOGANY LEDGE
OUTCROP MAHOGANY LEDGE
PIACEANCE CR.
PARACHUTE CR.
RIFLE
COLORADO RIVER
UTAH
COLORADO
INDEX MAP
SHOWING LOCATION OF SELECTED STREAM GAGING STATIONS AND CONTEMPLATED OIL SHALE DEVELOPMENTS
▲ STREAM GAGING STATION

Figure 4-1. Location of Selected Stream Gaging Stations and Oil Shale Developments

Table 4-5. Summary of Piceance and Yellow Creek Streamflow Records (25)

Location	Period of Record	Drainage Area (sq.km) (sq.miles)	Average Discharge m^3/min (cfs)	Extremes of Discharge m^3/min (cfs)	
				Max	Min
Piceance Creek at Rio Blanco (4)	10/52-9/57	23 (9)	2.4 (1.4)	39 (23)	0.2 (0.1)
Piceance Creek below Rio Blanco (5)	10/40-9/53	396 (153)	35 (20.3)	731 (430)	0.2 (0.1)
Piceance Creek below Ryan Gulch (6)	10/64-9/67	1256 485	21 (12.2)	680 (400)	1.4 (0.8)
Piceance Creek at White River (7)	10/64-9/66	1629 (629)	29 (17.0)	935 (550)	1.3 (0.9)
Yellow Creek near White River (8)	10/64-9/66	668 (258)	2.3 (1.37)	1802 (1060)	0.0 (0.0)

( ) See Figure 4-1 for location

Roan and Parachute Creeks. Roan and Parachute Creeks have peak flow during spring snowmelt and low flows during autumn and winter (26). Although Roan Creek flows throughout the year, Parachute Creek is often dry from December through April. Table 4-6 summarizes streamflow records at three locations on the Parachute Creek drainage and three locations on the Roan Creek drainage. Average annual discharges of Parachute Creek and Roan Creek into the Colorado River are about 14,000 and 26,000 acre feet of water, respectively.

Chemical analyses of waters from Parachute and Roan Creek show the streams to have similar water quality characteristics. Dominant ions are calcium, magnesium, sodium, bicarbonate and sulfate; TDS content increases in the downstream direction. Disproportionate increases in sulfate content are observed in the lower reaches of both streams.

4.2.1.3 Uinta Basin

The oil shale deposits of the eastern Uinta basin are drained by the White River. Most of the flow in the White comes from snowmelt in the Colorado mountains. Local streams contribute very little water to the White. Streamflow records for the White River near Watson, Utah show a mean discharge of about 750 cubic feet per second. Dissolved solids concentration ranges from 209 to 2380 mg/l (24); the discharge-weighted mean is about 426 mg/l.

Table 4-6. Summary of Roan and Parachute Creek Streamflow Records (25)

Station Location (Number refers to Fig. 4-1)	Period of Record	Drainage Area (sq.km) (sq.miles)	Average Discharge m³/min (cfs)	Extremes of Discharge m³/min (cfs)	
				Max	Min
W. Fork Parachute Creek (9)	10/57-9/62	124 (48.1)	7.43 (4.37)	250 (147)	0
Parachute Creek near Union Operation (10)	10/48-9/54 10/64-9/67	374 (144)	30.0 (17.7)	1255 (738)	0
Parachute Creek near Grand Valley (11)	4/21-10/27	518 (200)	51.5 (30.3)	1550 (912)	0
Roan Creek above Junction with Clear Creek (12)	10/62-9/67	391 (151)	25.2 (14.8)	1360 (800)	1.7 (1.0)
Clear Creek above Junction with Roan Creek (13)	7/66-9/67	287 (111)	---	2618 (1540)	0
Roan Creek near De Beque (14)	5/21-9/26	831 (321)	68.0 (40.0)	2074 (1220)	5.4 (3.2)

Streams in the Uinta basin, which originate in the area of the oil shale deposits, drain relatively low elevation watersheds. Consequently, except during periods of snowmelt or thunderstorms, local streams are dry or almost dry. Water quality of the local streams is generally poor. Boron, hardness and sulfate concentrations are high. TDS content is highly variable as a function of flow, and during late summer and autumn often exceeds 5000 mg/l (31).

Lease Tracts: The existing surface water quality at the federal lease tracts is summarized in Table 4-7. Maximum dissolved solids levels have exceeded the proposed water quality criteria at all the lease tracts. Fluoride has exceeded drinking water standards at tracts C-a and C-b; boron has exceeded agricultural standards at C-a. However, in many cases, the data in Table 4-7 represent a small number of samples. Mean annual discharges of Piceance and Yellow Creeks into the White River are 14,520 and 1,130 acre feet, respectively.

4.2.2 Existing Ground Water Quality and Yields

4.2.2.1 Piceance Creek Basin

- Bedrock Aquifers: Two bedrock aquifer systems are present in the Uinta and Green River formations of the Piceance Creek basin. The upper aquifer is present over the entire basin and is comprised of the fractured

Table 4-7. Maximum Values for Dissolved Constituents of Surface Waters on and Around Federal Oil Shale Lease Tracts (31,40,41)

Parameter	Units		C-a	C-b	Ua-Ub
		Water Quality Criteria [1]			
Dissolved Solids	mg/l	{500-1000 I(s)} {2000-5000I (t)}	2470	1450	536
Boron	mg/l	0.5I	0.77	0.330	0.090
Copper	mg/l	{0.2I} {1.0M}	0.008	0.010	0.013
Cyanide	mg/l	{0.005A} {0.2M}	0.02	0.03	0.01
		Drinking Water Regulations [2]			
Arsenic	mg/l	0.05	0.009	0.005	0.002
Barium	mg/l	1.0	0.40	0.20	0.140
Cadmium	mg/l	0.010	0.003	0.006	0.004
Chromium	mg/l	0.05	0.080	0.020	0.010
Lead	mg/l	0.05	0.009	0.011	0.005
Mercury	mg/l	0.002	0.001	0.0008	0.0002
Nitrate as N	mg/l	10	2.2	1.9	0.36
Selenium	mg/l	0.01	0.006	0.005	0.002
Silver	mg/l	0.05	0.002	----	0.000
Fluoride	mg/l	(3)	10	1.3	0.3

1) Proposed Criteria for Water Quality, Volume I, October 1973, U.S. Environmental Protection Agency
2) Federal Register, Wednesday, December 24, 1975, Environmental Protection Agency, Water Programs, National Interim Primary Drinking Water Regulations Maximum Contaminant Levels.
3) Limits on fluoride depend upon annual average air temperature. Allowable fluoride concentration range: 1.4 mg/l @ 90.5°F to 2.4 mg/l @ below 53.7°F.

I = irrigation (t) tolerant crops; (s) sensitive crops
M = Municipal drinking water
A = Aquatic life

lean oil shales of the Green River formation and overlying fractured marlstones, siltstones and sandstones of the Uinta formation, above the Mahogany zone. The lower aquifer consists of fractured and leached oil shale below the Mahogany zone and is best developed in the north central part of the basin where it is commonly called the "leached zone." The Mahogany zone appears to impede flow between the two aquifers over most of the basin.

The total amount of ground water in the Piceance Creek basin has yet to be accurately determined. However, the Department of Interior estimates that the basin may contain as much as 25 million acre feet of water in the upper aquifer (24). Weichman estimates that the lower aquifer may contain as much as 25 billion cubic meters (20 million acre-feet) of water (28).

Ground water movement in the basin parallels surface stream flow. North of the topographic divide that separates the Piceance-Yellow Creek and Parachute-Roan Creek drainages, surface and groundwater movement is to the north. South of this divide, ground water movement is toward the south.

Most of the aquifer system recharge comes from melting of the heavy snowpack found at higher elevations around the margin of the basin. In these recharge areas water percolates downward into the upper aquifer through the Mahogany zone and into the lower aquifer charging both aquifers. The ground water then moves laterally to the discharge areas.

In the northern part of the basin, water moves upward from the lower aquifer through the Mahogany zone and into the upper aquifer, and is then discharged into the alluvium of Piceance and Yellow Creeks, ultimately reaching the surface. At the southern margin of the basin, most of the water is discharged by springs along the sinuous line of cliffs near the top of the Mahogany zone.

Using limited hydrologic data obtained from test wells, the USGS and others have made model studies of the hydrologic system of the Piceance Creek basin to estimate the quantity of water that will be produced in conjunction with mine dewatering, and to determine the effects of dewatering on the surface and subsurface hydrologic regimes. It is estimated that in the northern part of the basin, discharge rates of more than 1.7 m^3 (60 ft^3) per second may be required to keep the mine workings dry (23,30). The net result of this water removal over a period of years will be to locally reduce spring and streamflow. In the southern margin of the basin, the quantity of water produced by dewatering will be considerably smaller by comparison and the effects will be more localized.

Although the chemical quality of the groundwater in the Piceance Creek basin varies widely, both the upper and lower aquifers can be classified as containing sodium bicarbonate type water, and the concentration of dissolved solids generally increases in the direction of flow.

In the recharge areas, the dissolved solids content of upper aquifer waters average about 500 mg/l. At the northern discharge area the dissolved solids content of upper aquifer water averages about 2000 mg/l. At the southern discharge areas, the dissolved solids content of the upper aquifer averages about 1000 mg/l. Fluoride content of the upper aquifer often exceeds 10 mg/l in the northern part of the basin; but averages less than 0.5 mg/l at the southern margin.

The dissolved solids content of the lower aquifer increases both with depth and in the direction of flow. In the recharge area the dissolved solids concentration of the lower aquifer is of the order of 1000 mg/l. This increases to more than 30,000 mg/l at the discharge area at the northern margin of the basin. In individual wells in the north central part of the basin, the dissolved solids content of water taken near the top of the lower aquifer is as low as 2000 mg/l while in samples taken near the base of the "leached zone" the dissolved solids content is more than 60,000 mg/l. The ground water in the lower aquifer contains exceptionally high concentrations of dissolved fluoride, with an average level of nearly 10 times the recommended value for most uses. The areal distribution of fluoride has no discernible pattern.

- Alluvial Aquifers: The alluvial aquifers in the Piceance Creek basin are limited to valley bottoms along creeks. These aquifers are generally less than .8 KM (0.5 mile) in width and less than 43 M (140 feet) thick. Although the alluvium is capable of transmitting and storing more water per unit volume than the bedrock aquifers, the areal extent is small. Consequently, high discharge rates can only be maintained briefly. Water in the alluvium occurs both under water-table and artesian conditions, depending upon the occurrence of clay beds.

The alluvial aquifers are recharged by precipitation, applied surface water, streams and infiltration from bedrock aquifers. The aquifer discharges to streams, springs, and wells and to the atmosphere by evapotranspiration.

Water in the alluvium has about the same chemical character as water in the stream, but usually exhibits a higher dissolved solids concentration. Along Piceance Creek, dissolved solids content ranges from less than 500 to more than 8000 mg/l. Water in the alluvium of Yellow Creek and Parachute Creek includes calcium, magnesium, sodium, bicarbonate and sulfate. The dissolved solids concentration of the water is sometimes as much as 7200 mg/l. The sulfate concentration of a water sample near the mouth of Roan Creek was 4200 mg/l (25).

Table 4-6 summarizes the groundwater quality data which have been collected at lease tracts C-a and C-b. Dissolved solids, fluoride, and boron levels in the lower aquifers exceed water quality criteria and/or drinking water standards at both tracts. Boron and copper in the alluvial aquifer at tract C-a exceed irrigation standards while cadmium and lead exceed drinking water standards. The data in Table 4-6 represent a limited number of analyses for many constituents, and may not be completely representative.

Table 4-8. Mean Values for Dissolved Constituents in Groundwater on Federal Oil Shale Lease Tracts C-a and C-b (15,17,40)

			C-a			C-b		
Parameter	Units	Water Quality Criteria[1]	Alluvial Aquifer	Oil Shale Aquifers Upper	Oil Shale Aquifers Lower	Alluvial Aquifer	Oil Shale Aquifers Upper	Oil Shale Aquifers Lower
Dissolved Solids	mg/l	500-1000 I(s) 2000-5000 I(t)	1740.065	1140.000	1550.000	1000.000	560.200	750.000
Boron	mg/l	0.5 I	1.250	.692	1.630	.320	1.500	3.006
Copper	mg/l	0.2 I	.174	.027	.019	——	——	——
		1.0 M	.524	.027	.019	——	——	——
Cyanide	mg/l	0.005 A	.002	.000	.005	——	——	——
	mg/l	0.2 M	.002	.000	.005	——	——	——
		Drinking Water Regulations[2]						
Arsenic	mg/l	0.05	.009	.004	.007	.006	.014*	.020*
Barium	mg/l	1.0	.003	.000	.000	.290	.700*	1.000*
Cadmium	mg/l	0.010	.029	.002	.001	——	——	——
Chromium	mg/l	0.05	.005	.005	.000	——	——	——
Lead	mg/l	0.05	.396	.353	.047	.026	.012*	.030*
Mercury	mg/l	0.002	.000	.030	.000	.023	.007*	.007*
Nitrate as N	mg/l	10.	6.600	.534	.765	3.100	.470*	.790*
Selenium	mg/l	0.01	.008	.002	.000	——	——	——
Silver	mg/l	0.05	.506	.007	.023	——	——	——
Fluoride	mg/l	(3)	.367	4.200	13.700	.97	18.300	19.020

1. Proposed Criteria for Water Quality, Volume I, October 1973, U.S. Environmental Protection Agency.
2. Federal Register, Wednesday, December 24, 1975, Environmental Protection Agency, Water Programs, National Interim Primary Drinking Water Regs., Maximum Contaminant Levels
3. Limits on fluoride depend upon annual average air temperature. Allowable fluoride concentration range: 1.4 mg/l @ 90.5°F to 2.4 mg/l @ below 53.7°F.

I = Irrigation (t) tolerant crops; (s) sensitive crops
M = Municipal drinking water
A = Aquatic life

*Mean chemical concentration based on swab tests of saturated sequence in question.

4.2.2.2 Uinta Basin

Little information is available on the ground water hydrology of the Uinta basin. Hydrologic test information from a few scattered wells indicate that groundwater can be found in the sandstone and siltstone beds above and below the oil shale and within fractures of the oil shale. However, based on current data, it is unlikely that any of the aquifers contain significant amounts of water.

The Green River formation probably contains more water than any other formation in the Uinta basin. Several aquifers have been identified in test wells, but the lateral extent of these zones has yet to be determined. Hydrologic investigations in connection with the U-a and U-b baseline studies have established the presence of an aquifer about 100 feet thick lying about 350 feet above the Mahogany zone (21). The aquifer crops out along the White River and Evacuation Creek and extends an undetermined distance northwestward beyond the tract boundaries. The aquifer is recharged along the outcrop; the discharge area is not known. Ground water movement is to the northwest. Pump tests run in 4 holes yielded from 18-6500 liters (5 to 1750 gallons) of water per minute, with dissolved solids content of the produced water ranging from 1000 to 3500 mg/l (31). Elsewhere in the basin, the Green River formation has yielded only small quantities of water with up to 72,000 mg/l dissolved solids content.

4.2.3 Effects of Water Withdrawal by Oil Shale Development on the White and Colorado Rivers

One estimate of the total supply of surface water available to the oil shale developments is estimated at 526 million m^3 (427,000 acre-ft) per year (13). This supply of water would be derived primarily from two river basins, the White River and the Colorado River. The major potential developments that may utilize water from the White River basin are: Colorado federal oil shale lease tracts C-a and C-b, Utah federal oil shale lease tracts U-a and U-b, TOSCO (sand wash), and Superior Oil Company. The developments that will likely obtain their water from the Colorado River Basin are: Occidental Oil Company (modified in-situ development), Colony (TOSCO II) development, Union Oil Company of California and the Paraho Gas Combustion demonstration plant at Anvil Points near Rifle, Colorado.

Although the exact water requirement for each of these developments at their full scale operation is uncertain at the present time, it has been estimated that for every cubic meter of oil produced, an approximate average of 3.7 cubic meters of water will be required (see Section 3.2.1). If this approximation is realistic, then surface water might support an oil shale industry producing about 390,000 m^3/day (2.4 million barrels/day) of shale oil. However, the shale industry will have to compete with agriculture, mining, industry, and urban users for this surface water.

Some of the water requirements for development will be met by groundwater sources in the Piceance Basin. Deeper aquifer water may be considered "geologic" water and its withdrawal for consumptive use may have little or no effect on surface flows. However, shallow aquifer water withdrawal for mine dewatering purposes and process needs will likely diminish local surface flows, and ultimately, the flows in the White and Colorado Rivers. For the first phases of oil shale development, lease tracts C-a and C-b, Superior Oil Company will use entirely or primarily groundwater to supply process needs. The extent to which surface water must supplement groundwater for expanded operations is not known at present.

One effect of withdrawing water from the White and/or Colorado Rivers is a potential salinity increase downstream. Since the White River merges with the Green River and ultimately the Colorado River, the effects of increased salinity will be seen at downstream reservoirs on the Colorado River (e.g., Hoover or Imperial Dam). In general, salinity of the water will increase progressively from the head waters to the lower reaches of the Colorado River. Two factors contribute to increased salinity: (1) increased salt loading, and (2) salt concentration. Salt loading is caused by both natural and manmade sources which contribute salts to the rivers. Salt concentrating effects are produced by removing and consuming relatively high quality water or by evaporation in reservoirs and in irrigation systems, therebyconcentrating salts into a lesser volume of water.

Several estimates have been made of the effects of individual oil shale development projects on the salinity in the Colorado River. Results of these estimates indicate that the salinity increase due to the individual withdrawals in no case exceeds 7.0 mg/l of total dissolved solids at Imperial Dam (13). One estimate for a 40,000 m^3/day (250,000 bbl/day) oil shale industry shows a salinity increase of 1.0 mg/l at Hoover Dam (14). According to the final EIS of the Department of Interior for a prototype oil shale leasing program, the salinity at Hoover Dam will increase by about 10 to 15 mg/l for a 1,000,000 bbl/day (160,000 m^3/day) oil shale industry requiring 149 million m^3 (121,000 acre-ft) to 233 million m^3 (189,000 acre-ft) of water per year (24).

It is possible that certain oil shale withdrawals may actually enhance water quality in the Colorado system by consuming high dissolved solids water which would otherwise reach surface waters. Consumptive use of Piceance Creek water (for example, by Superior Oil Company in the Northern Piceance Basin) may improve the quality of the White River below its confluence with Piceance Creek. (Tables 4-4 and 4-7 show the approximate dissolved solids levels for the White River and for Piceance Creek near tract C-b, respectively). The Rio Blanco oil shale project (tract C-a) has indicated that oil shale development on that tract will actually cause a decrease in salinity in the lower Colorado system via use of saline groundwater which would otherwise reach the White River (see Table 4-8 and Reference 17).

Based on the above estimates, salinity increase due to consumptive withdrawal for oil shale development is expected to have minimum impact on existing water users (including municipal, industrial, agricultural, hydroelectric, recreational users). More significant water quality impacts on either the White or the Colorado Rivers may result from (1) uncontrolled leachate reaching groundwater or draining into surface streams leading to the rivers and (2) failure of holding ponds or disposal pile. A discussion of these potential impacts may be found in other sections of this report.

4.2.4 Effects of Development on Local Surface and Groundwater

All of the proposed programs for oil shale development announced to date have set forth a policy of no direct discharge of wastewaters during commercial operations. However, even if this policy is strictly followed, other potential sources of pollution may exist. Some activities, which have no effluent products, may indirectly affect water quality. Accidents may also cause the release contaminates into the ground or surface waters.

Water can be indirectly contaminated by activities which unbalance the existing hydrologic regime. Water can also be indirectly contaminated by the failure of systems designed to contain or confine direct effluents. Accidental leaks, spills, and dam overflows may contaminate surface streams.

Most of the activities that could cause or lead to indirect water pollution are common to several or all of the proposed developments. These non-site specific activities along with the proposed plan for mitigating water quality degradation are discussed below. Site specific activities and proposed mitigation plans are discussed in the succeeding section. Accidental sources of water pollution and control plans are discussed in the last section.

General Indirect Water Pollution Sources and Control Plans (1,2,17,24)

- Construction Activities: Irrespective of location, construction activities will be a necessary part of all oil shale developments. Construction activities include the development of the mine and plant sites, establishment of the processed shale and overburden disposal areas, development of ore stockpiles, upgrading of existing roads, and construction of new roads, service corridors, dams, reservoirs, etc. The major effects of these landscape modifications will be to increase runoff which will, in turn, lead to increased erosion and sediment load in local streams. Concentration of dissolved solids in the runoff may also be higher than that from undisturbed terrain, depending upon the nature and properties of the surfaces that are exposed.

In order to prevent runoff waters from modified land surfaces from entering streams, dams will be built downstream of the construction activities. The waters collected by these structures will be used on site. Other water control structures will be built to prevent erosion and control sedimentation as needed. In general, stream sediment load and siltation will be minimized by disturbing vegetation and soil as little as possible by contour grading and by installing catchment basins and initiating restoration activities as soon as feasible.

- Mining Activities: The mining of oil shale can indirectly affect water quality in several ways. Mining will necessitate dewatering when operations make contact with the aquifer. Dewatering has two important aspects: (1) groundwater produced by the dewatering could pollute streams if not controlled and (2) dewatering could reduce or dry up spring and stream flow. Also, subsidence of underground workings is a threat to the surface and subsurface waters. Rupturing of strata that naturally impedes vertical flow could allow poor quality water to reach the surface. Subsidence of the land surface would alter stream course and increase sediment and dissolved solids content.

Proposed development plans indicate that during full-scale operations, all water from dewatering operations (supplemented by water from outside sources) will be utilized in processing and for retorted shale disposal. During pre-commercial development, however, surplus water may be obtained from the dewatering operations. Depending upon amounts and location, several techniques will be used to handle this surplus water. These include: (1) storage with eventual later on-site reuse, (2) treatment to stream water quality standards and release, (3) use in construction, and (4) reinjection into the aquifers.

Because dewatering may diminish or dry up spring or stream flow, natural surface water augmentation is planned where necessary. Several options are available for providing this water such as: (1) release of supplemental water from upstream sources through natural stream channels, (2) additional development of groundwater sources, and (3) haulage, pipelines, or canals.

The effects of subsidence on surface and subsurface water quality are not fully understood at this time. Consequently, underground workings have been designed to minimize subsidence.

- Processing Activities: Processing produces a variety of waste materials that potentially could degrade water quality. The sources and characteristics of these solid and liquid wastes and plans for their disposal so as to prevent effluent discharge from directly entering surface waters are described in previous sections of this report (Sections 3-2 and 3-3). Generally, process wastewaters are not planned to be directly discharged. During plant upsets or accidental equipment failure, process wastewaters may be directly discharged to surface waters.

- Retorted Shale Disposal: Contamination of surface and groundwaters by salts, organic substances and trace constituents can occur as a result of erosion of, runoff from, and percolation through retorted shale. Such contamination may adversely affect the quality of water from other uses in the upper Colorado Basin (e.g., irrigation) and add to the salt loading of the lower Colorado Basin.

Like natural terrain, a disposal pile will be subject to surface erosion and runoff during storms and snowmelt. Soluble substances, particularly inorganic salts can be mobilized from retorted shale along with suspended material during the erosional process. About 10 kg/tonne (20 lbs/ton) of salt (primarily sodium sulfate) is water soluble in fresh, carbonaceous retorted shales (Table 3-14). Burned shales may contain larger quantities of soluble salts. Further, additional soluble substances are added to retorted shale in the form of process water (about 1 kg soluble salts/tonne of processed shale (1)).

Natural erosion in the Piceance Creek basin averages about 7 tonnes/hectare/year (3 tons/acre/year), although wide variations occur as a function of slope, storm frequency and intensity, vegetative cover, and properties of the local soils (44). Retorted shale subject to "average erosion" in the Piceance basin might contribute 70 kg (150 lbs) of salt along with 7 tonnes per hectare of suspended material to surface waters annually.

Although retorted shales have low permeability (Table 3-13), water has been shown to penetrate into retorted shale piles (43). Winter freeze-thaw cycles can significantly reduce compaction densities, creating greater permeability in the upper portion (~1 meter) of a pile than was originally the case.

Water will be normally applied to the surface of a disposal pile as part of the revegetation program (to supply water requirements of vegetation and to leach soluble salts to below the root zones). Such water applications encourage the establishment of capillary structure in TOSCO II retorted shale which allows both upward and downward migration of water. Salty deposits (mainly sodium and calcium sulfate) are occasionally observed as a thin crust on the surface of disposal piles between irrigation applications, particularly during hot weather when surface evaporation is high. These salty deposits will be partially dissolved by rain or snow and will add to the salt load of surface runoff.

Salts may also be solubilized by water percolating through retorted shale. Laboratory experiments have demonstrated that less salt is generally leachable from freshly retorted TOSCO II in percolation tests than in "blender" or "bottle" tests. The hydrophobic nature of carbonaceous retorted shale is thought to encourage channeling and inhibit thorough water-shale contact in the percolation tests. If TOSCO II retorted shale is wetted and then allowed to dry, a capillary structure is established which allows a more complete re-wetting at a later time. Upon prolonged water saturation, carbonaceous retorted shale loses some of its hydrophobic properties.

TOSCO II retorted shale can apparently allow percolation of water to occur, even when the pile is under-saturated with water. Freeze-thaw induced permeability increases in the surface layer of a pile over time, and the ability of the shale to allow downward water migration may contribute to deep water infiltration and capillary structure development (42). Water migrating through a pile can continue to dissolve salts until a concentration of about 1400 mg/l is attained in the interstitial solution. Percolate water, with a steady state dissolved solids content, may eventually mix with other groundwater, and/or reach surface waters.

Burned shales (e.g., gas combustion retorting) have little or no carbonaceous coating, and carbonate minerals have been partially calcined. Such shales are less hydrophobic than TOSCO II retorted shale, and contain salts in a more readily soluble form (42,43). Although fewer runoff and infiltration experiments have been conducted with burned shales than with TOSCO II shale, the results indicated that salts can be leached to below the root zone of most plants by repeated application of water to pile surfaces. Commonly, a cemented zone is established about 1-2 meters down after repeated water applications (37). This zone greatly reduces pile permeability and inhibits further downward migration of water. During the leaching process and the establishment of the cemented zone, runoff and any percolate waters will contain large amounts of dissolved salts.

In addition to the potential for mobilizing common inorganic ions from retorted shales, water running off of or migrating through a disposal pile may dissolve organic and trace inorganic constituents. Other solid and liquid wastes likely to be contained in a disposal pile (Sections 3.2 and 3.3) include process wastewaters, oily sludges, spent catalysts, and shale coke. Water contacting such materials may dissolve toxic or carcinogenic organic substances (phenolics, organic acids, POM) and hazardous trace elements (arsenic, nickel, molybedum, chromium). Since small scale experiments conducted to date have generally not included materials other than retorted shale, the potential for waterborne transport of suspended or dissolved substances derived from the above mentioned wastes is largely speculative.

Salts and other soluble substances, and suspended solids mobilized by water contacting retorted shale can be potentially controlled or contained. Minimizing pile slopes, constructing drainage systems, and providing impoundments below disposal areas can in principle decrease the extraction of salts, etc., and contain those which are extracted. Some of the site specific plans for such control are discussed in section 4.3. Despite controls, however, some runoff and percolate waters may eventually reach other ground and surface waters. Actual effects such as the salt loading of surface waters, will depend on a number of factors, including storm intensity and frequency, snowfall rates, distance which leachate waters must travel to reach groundwater or a surface water interface, and the rate of groundwater movement. Groundwater in the Piceance basin is thought to ultimately discharge into the alluvium of Piceance and Yellow Creeks in the northern part of the basin (Section 4.2.2). Movement of groundwater may be slow on the average, but periodic storm runoff and stream discharge may periodically flush salts into the White and Colorado River systems (indeed this is probably occuring naturally at present (44)).

Pollution Control Activities: The attempt to contain wastewaters may create an indirect source of water pollution. Leakage of poor quality water from impoundments is possible if the bottoms or dams of these impoundments are permeated. Eventual return of any of these contaminated waters to the surface through springs or baseflow would pollute streams in the area.

Infiltration of poor quality water from dams and reservoirs can be controlled in several ways. Reservoirs and other water control structures can be lined with impermeable material. Poor quality water that infiltrates into the groundwater system can be partially recaptured by shallow wells. If the reservoir is within the area of significant drawdown caused by mine dewatering, infiltrates may be collected by the mine dewatering system.

Site Specific Indirect Water Pollution Sources and Control Plans (2,17,46,48,51)

Variations in hydrology over the Piceance and Uinta Basins coupled with differing proposed methods of development create unique indirect sources of pollution. These are discussed below along with proposed control methods.

The Superior Oil Company lands are located at the northern margin of the basin near the junction of Piceance Creek and the White River (Figure 4-1).

It is Superior's intention to mine oil shale and associated sodium and aluminum minerals from the lower oil shale zone of the Green River Formation. As the proposed mine zone is below the lower aquifer and is indicated to be dry, dewatering of the mine zone may be unnecessary. Superior proposes to dispose of the processed shale in the mined-out zones, which may constitute an indirect source of pollution, however. Eventual percolation of groundwater through the underground processed shale disposal area could contaminate surface and groundwater of the area. However, it is envisioned that this would be controlled by compacting the processed shale to render it impermeable or by sealing off the minnd-out areas with barrier pillars.

Superior intends to use groundwater from the lower aquifer as the principal source of process water. This may reduce spring and streamflow in the area. However, as the spring and creek water in this part of the basin have a high dissolved solids content, this may actually improve water quality in the White River. If necessary, Superior intends to augment any water lost to the stream system as a result of their activities via release of purified process water (condensed process steam).

Tract C-a is located in the headwaters of Yellow Creek near the western margin of the basin (Figure 4-1). Stream water quality in this area is generally good. Both the upper and lower aquifers are moderately well-developed in the vicinity of the tract and contain water in the order of 1300 mg/l total dissolved solids with high fluoride content (Table 4-8).

The open pit mine contemplated for Tract C-a would remove the strata that presently restricts vertical movement of waters. As long as the pit is kept dry this would not create a problem. However, if the dewatering operation is permanently halted, the pit may fill with poor quality groundwater. It is possible that such groundwater could enter surface streams.

In order to prevent stream pollution, the pit could be lined with a layer of impermeable material or semi-impermeable retorted shale. Total backfilling or grouting is another option. A third option is to continue dewatering operations in perpetuity.

Tract C-b is located in the southcentral part of the Piceance basin. In this area surface water has a TDS content of about 1000 mg/l; fluoride content is moderate. Both the upper and lower aquifers are reasonably well-developed in this area. The TDS concentration of the water in both aquifers is about the same as the stream but fluoride content is higher (Tables 4-7 and 4-8).

Sprinkler irrigation and reinjection are two methods proposed for disposal of surplus mine water during construction. Both these methods could indirectly pollute ground and surface waters.

Evapotranspiration of high TDS and fluoride content water from the sprinkler system will build up salts in the soil that could be carried into the subsurface during periods of high precipitation. Eventual return of any of these contaminated waters to the surface through springs or baseflow would pollute streams in the area. Sprinkler irrigation would be used only in the area that is to be later occupied by the processed shale pile.

Data are insufficient to predict the total effects of reinjection on the hydrologic regime. However, if the water is reinjected into the same aquifer from which it came (as proposed), the potential for pollution is substantially reduced. Because the injected water will be later withdrawn as part of the dewatering scheme, the reinjection program may be considered as temporary storage rather than a permanent solution of the water disposal problem.

The present Occidental Oil Company operation is located in an oil shale outcrop area at the southern margin of the Piceance basin. Streamflow in this area only occurs during spring snowmelt and during thunderstorms. Limited amounts of groundwater are present in the upper aquifer; the lower aquifer is very poorly developed in this area.

Although Occidental proposes to develop the oil shale by in-situ methods, many of the water pollution problems associated with processed shale disposal are the same as for surface projects. Surface or ground water may percolate through the underground processed shale pile and become polluted. If this water is allowed to reach the streams in the area, severe water pollution and/or degradation may result.

It is assumed that a water retention facility will be built so as to collect any water that has filtered through the underground retort. This water could eventually be reused in the processing and mining operation.

The White River Oil Shale Project proposes to obtain water for development as tracts U-a and U-b from the White River. A dam has been proposed as a joint project of the state of Utah, the Ute Indians, and the Uinta Water Conservation District, to have a total dead storage capacity of 145 million m^3 (118,000 acre-feet) at completion. The impacts of dams on water quality in the arid west include evaporative losses (and salt concentrating effects), the deposition of sediment, erosion and dissolutionof bank material, the creation of new groundwater systems, and changes in downstream temperature regime and erosion potential. These and other potential impacts are not unique to the proposed White River dam, nor unique to oil shale development.

Accidental Sources of Water Pollution and Control Plans

Accidental sources of water pollution are the result of catastrophic events. These include dam failure and accidental spills of oil or other hazardous materials. Since spill contingency plans for oil and other hazardous materials must be submitted to the federal government and such plans are now in operation throughout the oil and chemical industries, no further discussion of this subject is included. The probability of sudden and complete dam failure, while remote, warrants further discussion, however.

Leachate from freshly retorted shale tests have a maximum TDS content of about 1400 mg/l (42). More typical concentrations of runoff waters are indicated to be about 20 percent of this value (1). While the quality of waters retained below processed shale embankments is highly variable depending upon dilution and evaporation, it appears that the TDS level of leachate water itself may be approximately the same as streams in the oil shale area. However, organic and trace inorganic constituents could be higher in leachate waters than in the streams.

Sudden dam failure would release the stored processed shale runoff and leachate water into the streams. Because the TDS of the stored water may not be dramatically greater than that of stream waters, dissolved solids content of the latter would not necessarily increase. Since the concentration of trace organic and inorganic constituents has not been quantified, it is presently not possible to determine the effects of these substances on water quality. Studies are in progress to determine the levels of trace materials in runoff and leachate from processed shale (1).

Sudden dam failure would send large quantities of water at high velocities along the stream channels. Extensive damage to the stream system in the form of erosion and siltation could occur. Suspended sediment levels would be increased both during and subsequent to the flood. Dwellings and other structures might be inundated. Much of the aquatic habitat and life could be destroyed. Damage and destruction caused by failure of a processed shale water retention dam would be similar to that caused by flash flooding of the same magnitude anywhere.

4.3 POTENTIAL IMPACTS ASSOCIATED WITH SOLID WASTE DISPOSAL

Solid waste streams are the largest by mass and volume of any waste streams encountered in the extraction and processing of oil shale. The bulk of these wastes are processed shale, raw shale fines, and dusts (as sludges) collected during processing. In addition, spent catalysts from shale oil upgrading operations, and sludges from plant water and wastewater treatment contribute to solid wastes requiring disposal. Also, retorted shale will commonly serve as the repository for process wastewaters which are used for moisturizing and compacting purposes. The sources and characteristics of solid and aqueous wastes were reviewed in Sections 3.2 and 3.3. This chapter is a review of solid waste disposal plans proposed by major oil shale developers. A discussion of the potential physical and vegetative stability of disposal piles and of solid wastes as an intermedia source of air and water pollutants is included.

4.3.1 Solid Waste Disposal Plans for Oil Shale Development

The developers of private oil shale lands (e.g., Colony, Union, Superior, Occidental) and of the federal lease tract lands (RBOSP-C-a, Roxana-C-b, and WROSP-U-a/U-b) have presented plans at varying levels of detail for handling, disposal, and stabilization of solid wastes from commercial operations. This section summarizes these plans and the physical setting of individual sites proposed for the disposal of wastes. All of the plans discussed below have the objective of creating a stable disposal pile, suitably contoured and revegetated, with provision for protection against leaching of substances into ground and runoff waters.

Colony (1): The Colony Development Operation has selected a canyon-type disposal site in Davis Gulch, near the Middle Fork of East Parachute Creek, in the northwest corner of the Dow West property. A schematic of the 800 acre disposal site is shown in Figure 4-2. An estimated 363 million tonnes (400 million tons) of waste will be placed in Davis Gulch and its side drainages during the first 20 years of Colony's planned plant operations.

Placement will be by means of 150 ton dump trucks spreading a layer 45 cm (18 inches) deep across the fill at one time. This will be followed by compaction to either 1360 kg/cu. meter (85 lbs/cu.ft.) in the pile interior or 1520 kg/cu. meter (95 lbs/cu.ft.) on frontal slopes, using a 12% average pile moisture content. A drainage system will be provided, together with a catchment basin and dam.

After final contours are established, contained salts in the top of the pile will be leached down into the pile, a 15 cm (6.0 inch) layer of topsoil added, and a revegetation program initiated. The latter will include the requisite chemical fertilization and irrigation over a period of several years to insure a stable, self-sufficient soil cover of about 45% grasses, 40% shrubs, and 15% forbs.

Tract C-b (2): The Roxana group (Ashland, Shell), which holds the federal lease of Tract C-b, intends to use TOSCO II retorting technology, and would therefore produce a processed shale and associated wastes similar to those described previously for the TOSCO II process (Section 3.3). The lessees would

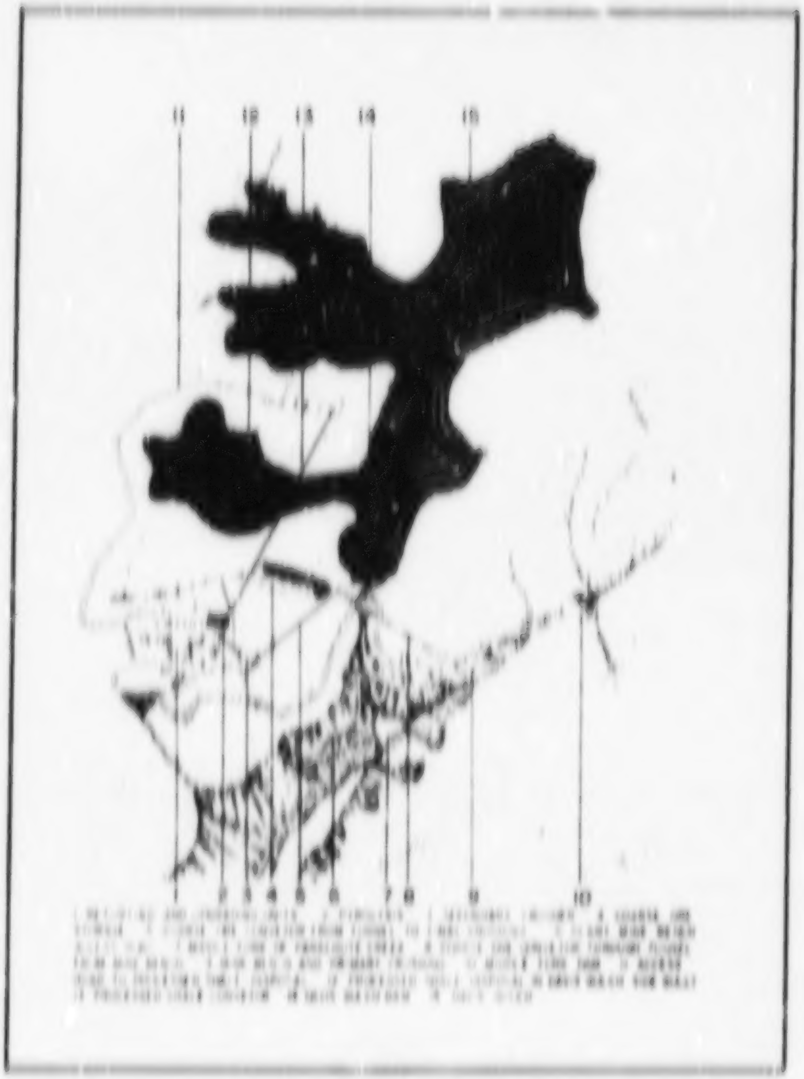
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Figure 4.2. Aerial View of Colony Development Operation Disposal Site - Davis Gulch (located at the upper reach of Parachute Creek, Colorado)(1)

prefer off-tract disposal of spent shale south of Tract C-b, but this currently is not likely for legal reasons. For on-tract disposal, a site in Sorghum Gulch has therefore been selected.

The disposal pile will eventually encompass some 486 hectares (1200 acres) after 20 years of plant production in an area over two miles long and over one-half mile wide, and have a pile height of 61 meters (200 ft). Processed shale will be produced at the rate of 49,000 tonnes (54,000 tons) per day (dry basis), or a total of 335 million tonnes (370 million tons) over the first 20 years. Disposal compaction procedures and provisions for runoff will be similar to those described for the Colony Operation.

Tract C-a (RBOSP) (17): Open pit extraction of oil shale for processing at Tract C-a will create several types of solid wastes requiring disposal. In addition to the processing wastes (retorted shale, catalysts, etc.), marginal quality oil shale (sub-ore), overburden rock, and soil material will require handling, relocation and/or disposal.

RBOSP indicates that materials removed from the open pit must be placed outside the pit for the first 2 phases of operation (about 30 years) so that maximum resource recovery from the tract can be realized and rehandling of material can be minimized. During Phase I operations, RBOSP proposes to dispose of overburden, sub-ore, and TOSCO II retorted shale at a site north of Tract C-a called "84 mesa". Figure 4-3 shows the proposed disposal location and a side view of the pile as envisioned.

The 144 hectare (355 acre) disposal area of Phase I will be segregated into sections containing soil, overburden, processed shale, and sub-ore. This segregation allows for later use of soil in revegetation operations, and potential recovery of sub-ore should it become economic. The top soil (and sub-soil) will be stripped from both the pit on Tract C-a and the disposal site on 84 mesa. RBOSP intends to use freshly stripped topsoil where possible to facilitate revegetation of disposal pile surfaces.

During Phase II, the disposal area will be expanded east and north to accommodate expanded solid waste generation on the tract (Figure 4-4). The nature of the wastes will change, since GCR retorting as well as TOSCO II retorting is envisioned. As in Phase I, overburden, sub-ore, processed shale, and topsoil will be segregated. All processed shale will be compacted as it is laid down, and exterior slopes of 4:1 will be established. An artificial soil profile, using freshly stripped topsoil where possible, will be placed on final surfaces. During Phase II, about 111,000 tonnes (120,000 tons) of moisturized process shale will be produced daily. At the end of Phase II the total volume of compacted processed shale and sub-ore/overburden will amount to 700 million cubic meters (915 million cubic yards) and 450 million cubic meters (593 million cubic yards), respectively.

Surface runoff from the pile will be collected by ditches around the pile perimeter. The outside of the shale pile will be highly compacted so as to minimize potential infiltration into the pile (with subsequent leaching). All runoff and possible leachate waters will be diverted to a lined collection

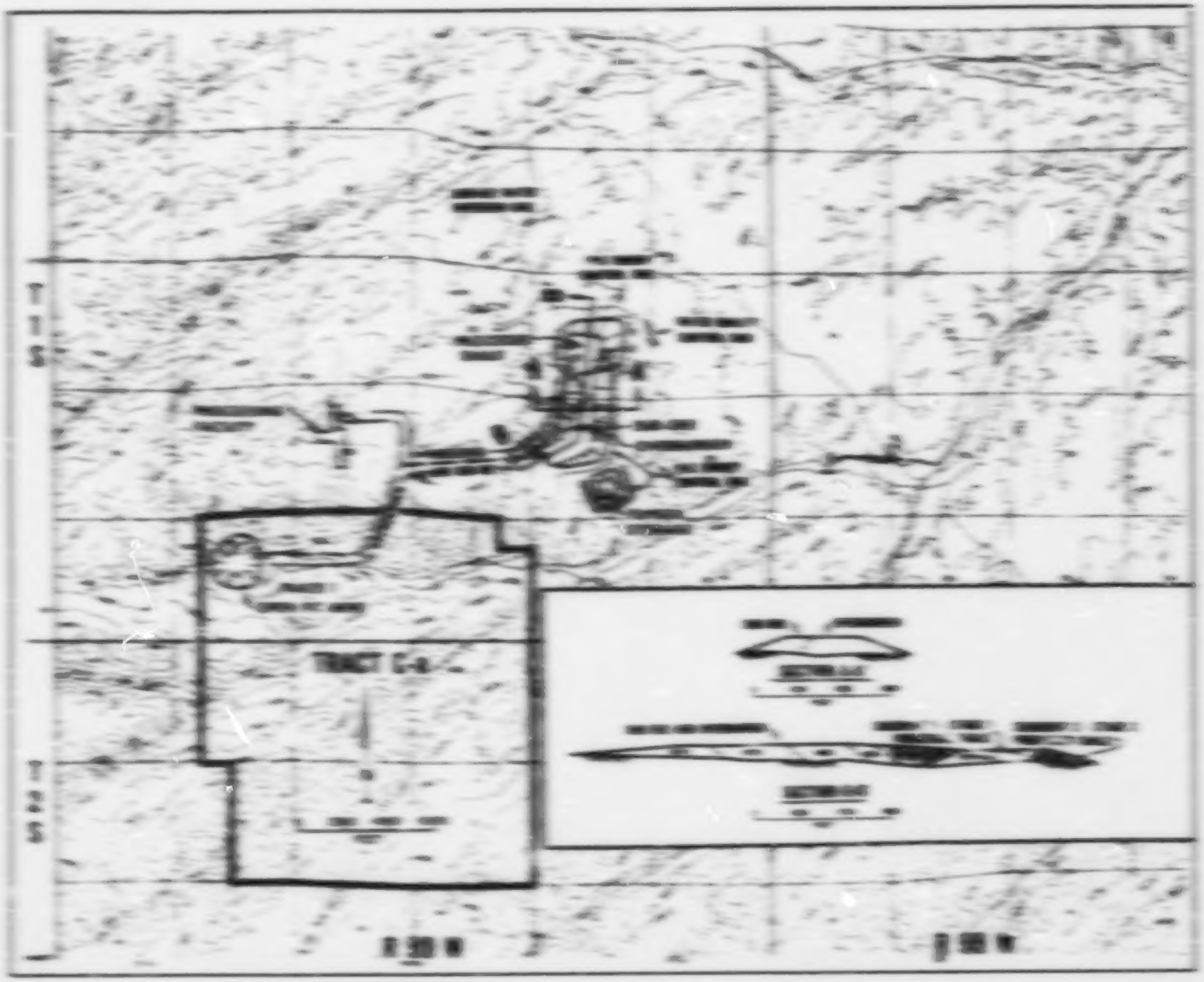
T 1 S
T 2 S
TRACT C-a
R 100 W
R 99 W

Figure 4-1. Tract C-a Conceptual Phase I Solid Waste Disposal Plan (17)

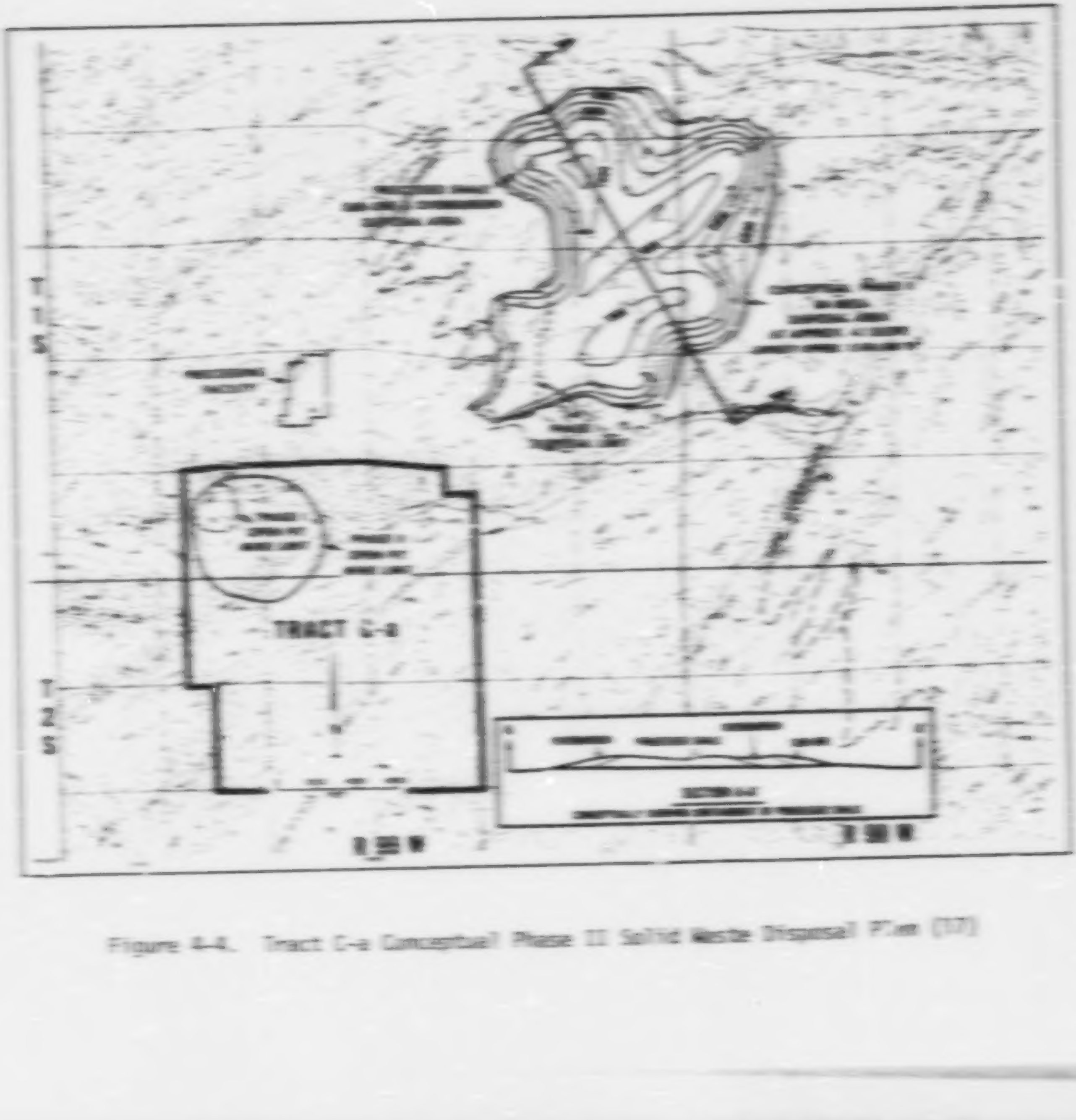
T 1 S
T 2 S
TRACT C-a

Figure 4-4. Tract C-a Conceptual Phase II Solid Waste Disposal Plan (17)

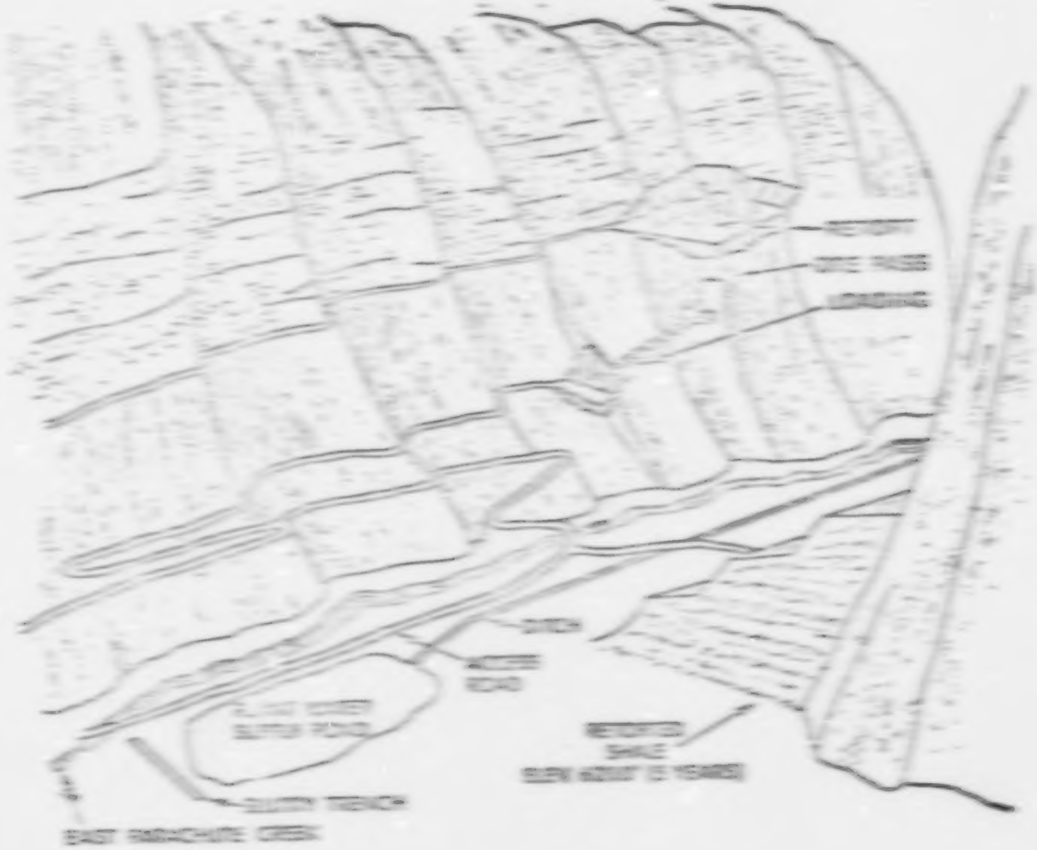
RETORT
ORE PASS
LOADING
DITCH
ACCESS ROAD
UTILITY TRENCH
EAST PARACHUTE CREEK
RETORTED SHALE

Figure 4-5. Schematic of Union Oil Company Retorted Shale Disposal Plan for Operations at Parachute Creek Site (45)

pond where the water will evaporate or be later used for dust control or compaction.

Union (45): The 9,000 tonnes (10,000 tons) per day modular plant proposed by Union Oil Company to be constructed on its land in Parachute Creek, will produce some 7,600 tonnes (8,360 tons) of retorted shale (dry basis) daily. This is approximately 2.8 million tonnes (3.1 million tons) per year, or 14 million tonnes (12.7 million tons) over the expected five years of operation of the modular plant.

Retorted shale from the processing plant at 2130 meter (7000 ft.) elevation will be conveyed downward through an ore pass to the 2010 meter (6,600 foot) level (see Figure 4-5), loaded into trucks, and transported to a disposal area in East Parachute Creek canyon. Here, it will be deposited in windrows up the south embankment of the canyon and compacted to a density of 1,440 kg/cu. meter (90 lbs/cu.ft.).

Runoff from the disposal pile will be caught in a leachate collection ditch at the top of the embankment. The East Fork of Parachute Creek will be re-routed around the embankment through a by-pass ditch.

If a full-scale commercial plant is later constructed by Union Oil it would produce some 47,000 tonnes (52,000 tons) of spent shale per day, or 15.5 million tons per 330 day stream year.

Tract U-a, U-b: (51) The joint development of Tracts U-a and U-b is intended to proceed through an initial modular plant stage with a throughput of 9,100 tonnes (10,000 tons) of raw shale per day, to a first commercial plant processing 72,500 tonnes (80,000 tons) per day, and finally to a projected plant handling 145,000 tonnes (160,000 tons) of shale per day. The latter plant will produce some 118,000 tonnes (130,000 tons) of processed shale daily or approximately 39 million tonnes (43 million tons) per stream year.

It is currently intended that the major portion (85%) of retorting will be carried out in vertical, Paraho direct and/or indirect type retorts, but that the crushing fines (15%) will be pyrolyzed in TOSCO II-type retorts. The processed shale will therefore be primarily of the Paraho-type, with some 15% of it having the properties previously described for TOSCO II spent shales.

It is expected that all of the 16,000 cubic meters (100,000 barrels) of shale oil produced daily will be upgraded in facilities similar to those used for the Colony Operation. As a result, some 3% of the wastes will consist of spent catalysts, sludges, and arsenic-laden solids from shale oil processing.

Spent shale and waste disposal is expected to be on Tract U-a, in Southam Canyon, to the west of the plant area. The processed shale pile will be built southward along the eastern half of the canyon toward the southern limits of Tract U-a. A retention dam at the northern end of the canyon will prevent contamination of the White River. The finished processed shale disposal pile will be contoured to blend with the natural terrain, and revegetated.

It is projected that the combined 72,500 tonnes/day and 145,000 tonnes/day commercial operations will produce of a total of about 1,040 million tonnes (1,150 million tons) of retorted shale during the 20 (plus) years of contemplated full-scale production. This will result in a disposal pile in Southam Canyon of 727 million cubic meters (950 million cubic yards) volume, occupying some 366 hectares (900 acres), with an average depth of 61 meters (200 ft.).

Superior (28,46): The Superior multi-mineral process is unique in that it permits return of all processed (e.g. leached) shale underground, as a wet cake, for compaction into the void spaces remaining after room-and-pillar mining. It is expected that the 22,000 tonnes (24,000 tons) per day commercial operation will dispose of some 4.2 million tonnes (4.6 million tons) of leached spent shale annually.

The leached shale wet cake will be returned to the mine and converted into a slurry, which will be pumped into the empty underground rooms and allowed to drain to approximately 25% moisture content. Because of the dipping beds on the Superior property in the northern Piceance Basin in Colorado, it is claimed that the slurry can be emplaced up to the ceiling, by proper withdrawal of the slurry discharge pipe as each room fills.

As shown in Figure 4-6, the rooms will be grouped into a series of "cells" 460 meters x 820 meters (1,500 ft. x 2,600 ft.) with each cell enclosed by a rib pillar (barrier wall). Cells within a given level will be aligned with corresponding panels above and below. In the event of leakage, therefore, a given cell can be sealed off from the balance of the mine.

It is projected that each "cell" could contain up to 4.3 million tons of leached spent shale, which is approximately the amount expected to be disposed of annually from the commercial plant. No revegetation, of course, of the disposed shale will be required.

Occidental (47,48): In the modified vertical in-situ process currently under investigation by Occidental Oil Shale some 20% of the underground deposit must be mined out, in order to produce the requisite void space for subsequent rubblization. This mined rock must be disposed of, if it is too lean for surface retorting, or at least stored above ground if subsequent surface retorting is contemplated.

In a commercial Occidental in-situ operation using oil shale with an average assay of .06 m^3 /tonne (15 gallons/ton), and producing some 7,950 cubic meters (50,000 barrels) per calendar day, it is estimated that 51,400 tonnes (56,700 tons) of "rock" must be mined and removed daily, or approximately 18.8 million tonnes (20.7 million tons) annually. If this rock is very lean or nearly barren shale, it is proposed to dump it in canyons and gullies near the in-situ operations and restore a vegetative cover. The disposed material would be essentially the same as the parent rock from which local soils were derived. It is estimated that up to 16 to 24 hectares (40-60 acres) of typical canyon disposal area could be required annually for such purpose.

If the mined rock were richer in oil shale the above 50,000 barrel/day plant would produce, for example, only 31,000 tonnes/day of mined material for

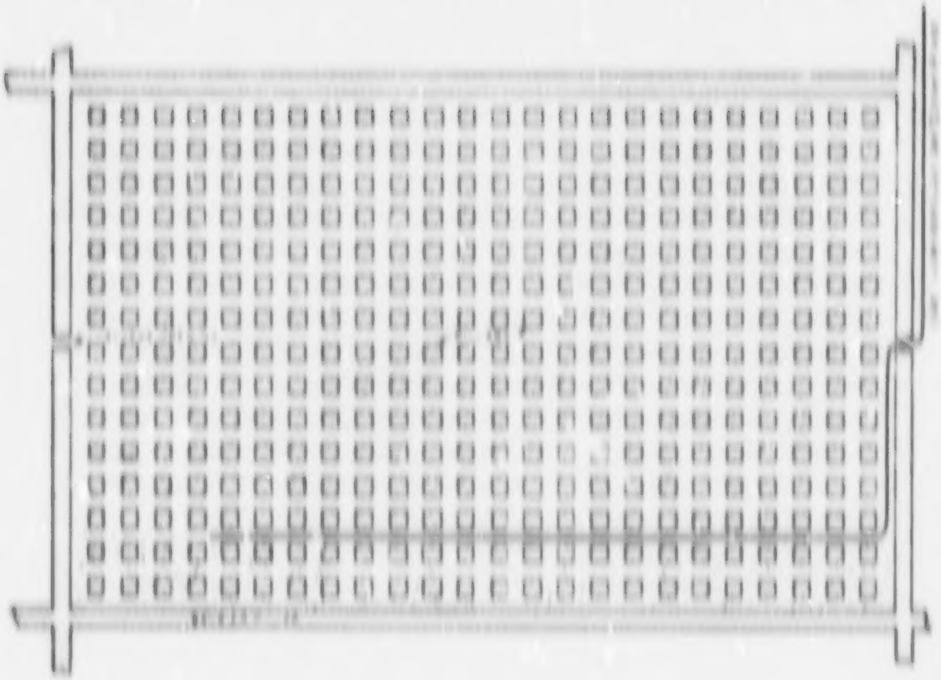

Figure 4-6. Backfilling of Mined Out Shale Zone with Processed Shale - Superior Oil Company (28)

a 25 gallon/ton deposit. This mined rock would most probably be stored temporarily and subsequently processed by surface retorting, producing some 26,000 tonnes/day of retorted shale for disposal. A canyon disposal area of some 8-12 (20-30 acres) annually would be required.

4.3.2 Potential Hazards and Pollution Problems

The disposal of processed (retorted) shale involves the transport and surface emplacement of large quantities of solids on a scale only rarely attained to date in the mining industry. The resulting disposal piles should be stable, resistant to substantial erosion, and essentially impervious to leaching by the normal rainfall and snowfall encountered in the shale region. Provision should be made for protection against the flash flooding which might rarely occur. A suitable, permanent vegetative cover should be established.

The spent shale will contain potentially leachable salts and in some cases a carbonaceous residue from retorting. In addition, if upgrading of shale oil is carried out in conjunction with retorting, spent catalysts, sludges, arsenic-laden solids, and other plant wastes might also be present in a disposal pile. The latter could include process waters which might be used to aid in compacting the processed shale.

In the light of the above it would therefore appear that potential hazards exist relating to (a) pile stability, (b) airborne particulates, odors, and/or organic vapors, (c) leachates, both inorganic and organic, as a result of precipitation and/or ground waters, (d) transfer of possible hazardous organics or trace elements to the biosphere, and (e) trans-locations of toxic substances to vegetation.

Pile Stability

Most of the proposed major oil shale developers, as previously discussed, plan to dispose of processed shale and also, perhaps, associated plant wastes in canyon (or gully) locations. Colony has selected a 325 hectare (800 acres) site in Davis Gulch, Middle Fork, East Parachute Creek. Union's disposal area will be in East Parachute Creek Canyon. The Roxana Group (Tract C-b) will utilize a 490 hectare (1200 acre) on-tract site in Sorghum Gulch (Piceance Basin). RBOSP plans to use "84 mesa" north of Tract C-a. Tracts U-a/U-b will utilize 366 hectares (900 acres) in Southam Canyon on Tract U-a.

Among the surface process developers only Superior Oil will not use a canyon disposal site, but rather return its retorted (leached) shale to its underground mine. Occidental will, of course, leave its retorted shale in-place after in-situ retorting, but may dispose of mined lean shale or barren rock on-surface.

The large volumes of material which will be present in a disposal pile can create pollution problems should the pile experience mass movements. Slope stability and liquefaction studies have been conducted for TOSCO II process shales (49,50). Large scale flow type failure of a pile is predicted to be an unlikely occurrence. However, local slumping or building is a more probable event. The angle of internal friction for TOSCO II retorted shale is about 20°, suggesting that slopes of 3:1 (18.5°) would be stable in principle. Slopes of 4:1 are generally proposed for the sides of shale embankments, corresponding to a 14° angle of internal friction. The safety factor is not extremely high, and uncertainty exists regarding degree of saturation of some shale zones during part of the year. Several potential interfaces between different materials are present in proposed disposal piles including Valley floor - pile side interfaces, compacted - non-compacted interfaces, overburden - processed shale interfaces, and topsoil - processed shale interfaces. These interfaces may promote lubrication, particularly when water saturated, and allow mass movement to occur.

Mass movement could adversely affect water quality. Sediment and salts can be added to local surface waters, or to catchment structures. Also, changes in pile drainage systems due to slumping, etc. may encourage infiltration. A destabilized pile surface will also be difficult to keep vegetated, and both increased surface wind and water erosion may result.

Since no large disposal piles have been constructed to date, little is actually known about stability of such piles in real situations. Further, most of the work to date has dealt with carbonaceous shales; burned shales are likely to have significantly different stability properties.

Intermedia Transfer of Pollutants from Disposal Piles

In order to control fugitive dusts, and also to provide moisture for compaction and stabilizing the disposal piles, retorted shale will be wetted prior to transport and distribution. Whether this will be sufficient to minimize particulate emissions at the scale of operations contemplated at each site is currently not completely known. The characteristics of the spent shale and the micro-meteorology for a given site are among the pertinent variables involved.

Indirect water pollution resulting from runoff from and infiltration into disposal piles has been discussed in Section 4.2.4. It is planned to route natural drainage at each disposal site around the pile or through the pile in conduits. Provisions must be made for drainages from side gullies, if present, and for protection of ground waters from leachate contamination. Whether the absorptive properties of the individual spent shales and the catchment basins planned by most developers are sufficient to insure environmental protection against water quality degradation is not yet clear.

4.3.3 Experience in Establishing Vegetative Cover on Retort Shale Piles

The surface of a disposal pile is subject to natural erosion by wind and water. In principle, non-vegetative protection or stabilization of pile surfaces is possible, but the large areas involved in commercial shale oil operations make vegetative stabilization the preferred or economic alternative. Further, successful vegetation programs can create a biotic habitat similar to or consistent with that of surrounding areas.

Several greenhouse and field experiments or tests have been conducted to investigate the potential of retorted shale to support plant growth. The results of these experiments indicate that successful establishment of vegetation directly on the surface of retorted shale piles is partially limited by inherent properties of retorted shale itself, including the high soluble salt content of the shale, the alkalinity of burned shale, the dark heat absorbing color of carbonaceous retorted shale, and the lack of nutrients needed for plant growth. Studies have shown that germination and growth of most plants are adversely affected when conductivity levels of soil saturation extracts exceed 4 mmhos/cm, and that high pH values are a detriment to plant growth (34,35,36). Direct exposure of carbonaceous retorted shale to sunlight can result in surface temperatures of up to 65°C (150°F), and such temperatures can prevent seed germanation (34). Retorted shale usually lacks sufficient available nitrogen and phosphorus to support vegetation.

Some of the properties of retorted shales which limit plant establishment and growth can be overcome. Retorted shale's salinity and alkalinity levels can be reduced by leaching the material prior to revegetation. However, channeling and incomplete wetting could result in pockets of unleached shale. Also, upper layers can become resalinized via the capillary movement of salts upward through the shale. Large accumulations of salts in the upper 3-5 inches of surface soil may be toxic to plants, even those with established root systems (38). For those retorted shales which have undergone significant carbonate decomposition (due to high retorting temperatures), the addition of granular sulfur effectively decreases alkalinity (37). But the effectiveness of this treatment is dependent on the adequacy of the moisture and temperature conditions at the site. The use of a light colored mulch, such as straw, decreases the heat absorbtion by the shale, and therefore, results in lower surface temperatures. However, straw has the disadvantage of being occasionally contaminated with weed seeds, and is also subject to dispersal by the strong winds that frequent some locations. The addition of a complete fertilizer has been shown to be a successful means of compensating for spent shale's lack of available nutrients.

Local climate, slope angle, and slope direction can have a large influence on the success of vegetative establishment. Precipitation in the Piceance Creek Basin in Colorado ranges from 30-40 cm (12-16 inches) per year, with the higher values occuring at higher elevations (mainly in the form of snow). In contrast, the Uinta Basin is essentially desert except where the White or Green Rivers form local riparian habitats. Rainfall is well below 25 cm (10 in)/year and vegetation is fairly sparse. Most of the oil shale related revegetation experiments to date have been conducted in the Piceance Basin (32,37,38,39). Only recently has revegetation been attempted in the harsher desert environment. The Research Foundation of Utah State University is performing an ambitious program of revegetation research for U-a/U-b (see Chapter 6).

Also, some of the earlier revegetation projects were conducted in relatively flat areas along river valleys. Slopes, particularly south facing, are much more difficult to revegetate than flat terrain or slopes facing north, east or west. Jute netting and various polymers are effective in decreasing surface erosion and thus are an aid in the initial establishment of plant cover on sloping surfaces.

An alternative to attempting establishment of vegetation directly on retorted shale is to construct a soil profile more conducive to plant growth. Developers of Tract C-a plan to place a layer of crushed rock and gravel between the spent shale and the soil layer in order to combat the capillary resalinization problem. But regardless of how the re-salinization problems are handled, the soil layer should be thick enough to (1) accommodate plants with extended root systems, and (2) be able to store adequate moisture for plant growth during dry periods. Retorted shale heat absorption problems could also be overcome with the placement of a layer of soil over the surface of the shale. However, at some locations there is not an adequate soil supply and the use of soil/retorted shale mixtures instead of soil alone may be necessary.

Some additional problems or areas of uncertainty have been identified in connection with revegetation experiments, including the following:

- A retorted shale pile will be compacted for physical stability. This practice, plus the cementation tendency of some shales may make portions of the embankment impenetrable to plant root systems and to percolating water. It may be difficult to establish deep rooted shrubs or trees on retorted shale piles.

- Success of revegetation may be hampered by foraging mice, rabbits, and deer. Such foraging may be partially controlled by fencing (for large mammals), but in any case the problem is not unique to the revegetation of retorted shale.

- Plants growing on retorted shale may contain higher levels of trace elements than plants growing on native soils. One study has indicated that zinc and molybdenum levels in vegetation growing on retorted shale exceeds that recommended in forage for cattle (38).

- Weedy species (eg, Russian Thistle) may invade revegetation sites. Initially, such invasion may not necessarily be undesirable, as "weeds" are commonly the first class of plants to become established in natural plant succession sequences. If a shale pile surface is particularly conducive to the growth of certain undesirable species, herbicides or other controls may be necessary.

- Although some small retorted shale piles have been revegetated and some have sustained vegetation for over 10 years without extensive management(1,37), the longer term stability and successional characteristics of such plots are not accurately known at present.

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5.0 THE REFINING AND END USE OF SHALE OIL PRODUCTS

The commercial success of shale oil will depend in part on the ultimate end use of the oil and on the refining steps necessary to produce a competitive product. This chapter is a brief review of shale oil upgrading and refining experiences to date, waste streams and hazards associated with refining and handling of shale oil, and emissions from the combustion of shale oil products.

5.1 UPGRADING AND REFINING OF SHALE OIL

Crude shale oil is a high nitrogen, moderate oxygen and sulfur containing oil having a relatively high pour point and viscosity. It contains a large fraction of unsaturated and aromatic compounds, and tends to form gums during storage. Compared to most conventional crude oils, shale oil yields less light ends upon distillation. Crude shale oil contains ash in the form of raw and retorted shale fines. Most trace elements in shale oil are associated with the ash fraction, and concentrate into higher boiling fractions and coke upon distillation. An exception is arsenic, which is found in essentially all distillate cuts. A summary of the properties of currently produced crude shale oils are presented in Table 5-1.

5.1.1 Upgrading Plans for Oil Shale Developments

The oil shale developments planned to date do not envision processing crude shale oil into a full range of refined products as would be the case with a modern petroleum refinery. Rather, various levels of upgrading or prerefining are planned in order to: 1) render crude shale oil transportable and/or suitable as a refinery feedstock and 2) produce fuel oil and other petroleum equivalent cuts for direct use. Table 5-2 summarizes the major prerefining or upgrading steps planned by oil shale projects. Some of the details of these steps are reviewed in Chapter 2 of this report.

Crude shale oil can be upgraded by employing variations of conventional petroleum refining techniques. Solids removal is accomplished by either filtration (diatomaceous earth) or by concentration of solids during coking. Saturation of olefins and removal of organic sulfur, oxygen, and nitrogen is accomplished by catalytic hydrogenation, although severe conditions must be employed with shale oils due to the high nitrogen content. Catalyst poisons such as arsenic are removed prior to hydrogenation, commonly by use of an adsorption catalyst.

5.1.2 Experiences in Oil Shale Refining

Essentially all major oil companies which have an interest in or hold mineral rights to oil shale have conducted research or demonstration programs to investigate the refining of shale oils. Generally, the results of such programs have not been published and are considered proprietary. Experiences from two relatively large scale refining runs with shale oil have been published and are briefly reviewed here.

Union Oil Company - 1961 (4)

The crude shale oil obtained from the Union Oil Retort A process is a waxy, intermediate gravity (specific gravity of 0.943), high in nitrogen (2.0 weight %), intermediate sulfur (0.9 weight %) crude, with a pour point of 26.7°C (80°F) and a viscosity of 46 centistokes (210 SUS) at 37.8°C (100°F). Early in 1961, approximately 3,180 m^3 (20,000 bbl) of the crude shale oil inventory at Union's Retort A demonstration plant were processed in the American Gilsonite's refinery near Fruita, Colorado. The basic operations in the refinery included delayed coking, thermal cracking, gasoline hydrogenation and catalytic reforming, light gasoline sweetening, and coke calcining. All of these operations were reported to be successfully applied to the Union Retort A shale oil in the refinery test run. The refined products were marketed by American Gilsonite through marketing outlets in the Grand Junction area.

The detailed results from shale oil refining at the American Gilsonite refinery are not available. According to Union Oil, the test results are similar to those obtained from the bench scale and pilot plant tests on shale oil refining performed by the Bureau of Mines. Based on the results of American Gilsonite refinery and Union's pilot plant test runs, preliminary process designs for producing and refining commercial shale oil were proposed by Union. The processes proposed included delayed coking to reduce pour point, Unifining* of the full range distillate to reduce nitrogen and sulfur content, and conventional refining processes of primary distillation, catalytic cracking, additional Unifining, reforming, alkylation and treating to produce LPG, gasoline, stove oil, jet fuels, heating oils, and diesel.

Paraho Shale Oil at Gary Western (1975) (5)

In 1975, a program under Navy Contract N00014-75-C-0055 was carried out by Applied Systems Corporation to demonstrate the production of military fuels from shale oil. Paraho crude from Anvil Point, Colorado, was selected as the raw material. Contractors included Applied Systems Corporation (ASC); SOHIO; Development Engineering, Inc., (DEI); Gary Western Co.; and Petroleum Analytical Research Corp., (PAR).

Using the Gary Western facility, at Gilsonite, Colorado, 9,956 barrels of crude Paraho processed shale oil were refined into the following quantities of military fuels:

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*Unifining is a hydrodesulfurization and hydrodenitrogenation process jointly licensed by Union Oil and Universal Oil Products Co.

Table 5-1. Summary of Crude Shale Oil Properties

Retort Type: Data Source:	Fischer Assay Ref. 1	TOSCO II Ref. 1	Paraho Direct Mode Ref. 4	Union Oil "B" Ref. 3	Occidental In-Situ Ref. 2
OIL PROPERTIES					
Gravity (°API)	20.7	21.2	19.3	22.7	22.5
Specific Gravity (60°F/60°F)	0.930	0.927	0.9383	0.912	0.904
Pour Point (°F)	75	80	85	60	70
Pour Point (°C)	23.8	27	—	—	21.
Viscosity (Centistokes)	23.72	22	—	—	13.1
Viscosity (SUS)	113 at 100°F	106 at 100°F	—	96.2	70.
weight % Carbon	85.23	85.1	84.90	84.8	84.86
weight % Hydrogen	11.38	11.6	11.50	11.67	11.80
weight % Nitrogen	1.80	1.9	2.19	1.74	1.50
weight % Oxygen	—	0.8	1.4	0.90	1.13
weight % Sulfur	0.98	0.9	0.61	0.81	0.71
weight % Ash	—		0.66	0.005	—
C/H Ratio	7.49	7.34	7.38	—	7.19
Fischer Assay of Feed (gpt)	26.7	—	—	24.2	15.25
Oil Recovery (% of Fischer)	100	100	—	97.0	--
ASTM DISTILLATION					
Initial Boiling Point, °F	192	200	270	139	—
10% Over	336	275	520	400	440
20%	430	410	600		—
30%	516	500	675		600
40%	—	620	750		—
50%	655	—	815	731	700
60%	685	775	845		—
70%	705	850	860		770
80%	Cracked	920	—		—
90%	—	—	—	980	920
End Point	—	—	—	1077	—

NATO Gasoline		116 m³ (725 barrels)
JP-4		72 m³ (454 barrels)
JP-5/Jet A		104 m³ (650 barrels)
DFM/DF-2		187 m³ (1,167 barrels)
Heavy fuel oil		442 m³ (2,765 barrels)
	Total	917 m³ (5,732 barrels)

The fuels met a majority of ASTM specification requirements. However, they did not meet specifications with respect to particulate matter, gum content, wax content, storage stability, and thermal stability. The opinion has been expressed that more rigorous hydrotreating (at 100-200 kg/cm^2 or 1500 to 3000 psi) and clay treatment might have allowed the final products to meet all ASTM specifications. The 672 m^3 (4224 BBLS) of original crude shale oil which do not appear in the military fuels are accounted for in coke, distillation gases, and flue gases from combustion.

Using modified refining techniques, based on preprocessing studies conducted by SOHIO, the Gary Western refinery operated at a rate of 2500 barrels a day to the coke/fractionator in relatively normal fashion, producing naphtha, liquid gas oil, heavy gas oil, heavy fuel oil, coke and gas.

It should be noted that this effort demonstrated only the feasibility of producing fuels from shale oil. Rates were below normal, yields were low, and the properties of the products were subnormal. However, none of the problems encountered were entirely unexpected and, generally, appear soluble with experience and practice.

The products from the Gary refining run were distributed to several laboratories, agencies and companies for testing,

- Wright Paterson AFB (Dayton, Ohio)
- Lewis Research Center (Cleveland, Ohio)
- Naval Air Propulsion Test Center (Trenton, N.J.)
- Mobil Equipment Research & Development Center (Ft. Belvoir, Va.)
- Energy Research Laboratory (Bartlesville, Okla.)
- Fuels & Lubricants Laboratory (San Antonio, Texas)
- Detroit Diesel-Allison/GM (Indianapolis, Ind.)
- Naval Ship Engineering Center (Philadelphia, Pa.)
- U.S. Coast Guard Station (Portsmouth, Va.)
- Southern California Edison (Los Angeles, Ca.)
- Cleveland Cliffs Iron Company (Cleveland, Ohio)
- Paraho Test Facility (Anvil Points)

Table 5-2. Summary of "In Situ" Upgrading of Shale Oil Planned at Development Sites

Project	Steps of Upgrading or Prerefining	Products
Colony Development Operation – Parachute Creek	• Distillation followed by delayed coking of residue • Dearsenation of naphtha and gas oil fractions • Catalytic hydrogenation of Naphtha and gas oil fractions • Hydrogen production by catalytic reforming of naphtha followed by steam, reforming shift conversion, CO_2 removal	• Low sulfur fuel oil • LPG • Coke • Sulfur • Ammonia
Lease Tract C-b	• Same as Colony	• Same as Colony
Lease Tract C-a	• Distillation, delayed coking • Dearsenation • Catalytic hydrogenation • Hydrogen production by gasification of heavy ends, followed by shift conversion & CO_2 removal	• Pipelineable shale oil • Upgraded shale oil • Coke • Sulfur • Ammonia
Lease Tracts U-a/U-b	• Catalytic hydrogenation of naphtha and crude shale oil. Hydrogen production by catalytic reforming of retort gases and naphtha.	• Refined shale oil • Sulfur • Ammonia
Union	• Solids/fines removal via filtration & water washing • Catalytic dearsenation • Stripping/stabilization	• Sulfur • Ammonia • Coke • Prerefined shale oil • Sulfur
Occidental	• No upgrading indicated, company claims oil can be transported directly to refinery	• Crude shale oil
Superior	• Company indicates that blending with petroleum crudes will be attempted	• Crude shale oil • Sodium bicarbonate • Alumina

5.2 WASTE STREAMS & HAZARDS ASSOCIATED WITH REFINING & HANDLING OF SHALE OIL

The waste streams which accompany shale oil upgrading and refining are similar to those encountered in conventional petroleum refining. Some of these emissions, effluents, and solid wastes (inventoried in Chapter 3.0) are associated with upgrading and refining operations.

5.2.1 Waste Streams

Preliminary examination of shale oil upgrading and refining operations (1,10,11,12) suggests the following:

- Atmospheric emissions from crude shale oil upgrading and refining are similar in magnitude and composition to those encountered with processing of petroleum. However, certain operations such as hydrogenation and ammonia and sulfur recovery must be tailored to the properties of shale oil, and pollution control equipment sized accordingly.
- Waste waters from shale oil processing contain organic and inorganic constituents similar to those found in the petroleum refining and byproduct coke industry.
- Solid wastes from shale oil upgrading and refining operations include spent catalysts, clay finishing wastes and perhaps shale oil coke. Such wastes may have somewhat different compositions and chemical properties than wastes from petroleum refining.

5.2.2 Carcinogenic Properties of Crude Shale Oils and Refined Products

Crude shale oils, upgraded or refined shale oil products, and certain waste streams associated with shale oil processing may contain hazardous substances from which industrial workers and the general population should be protected. A current concern is the potential human exposure to carcinogens associated with shale products. Several authors have suggested that shale derived oils may create more of a cancer hazard than is currently associated with petroleum oils (21,22,23,24), although the matter is still unresolved.

Epidemiological Studies

Early awareness of the potential carcinogenicity of shale oils occurred in the British cotton industry (8). A high incidence of scrotal cancer was attributed to direct worker contact with shale oil lubricants, used on the spinning machines. However, studies of workers in the Scottish oil shale industry during the same period did not reveal a particularly high cancer incidence in that industry. The Scottish experience indicated that only certain types of processed shale oils possessed carcinogenic properties.

The Estonian oil shale industry is one of the largest and oldest oil shale industries in the world. For over 20 years the Institute of Experimental and Clinical Medicine of the Estonian Ministry of Health has conducted clinical, industrial hygiene, and toxicological studies on the workers employed in this industry (8,9,10). A greater cancer incidence among Estonian shale workers over that of the general population has not been demonstrated. The Estonian shale industry attributes this lack of cancer problems to good hygiene practices, automation, and isolation of workers from potentially hazardous materials.

The largest current oil shale operation is the Petrobras Complex in Brazil. Although epidemiological data is limited, no special cancer problems have been reported for the operation.

The National Institute of Occupational Safety and Health (NIOSH) is sponsoring a study of workers involved in the production of shale oil from Colorado oil shale to investigate possible relationships between exposure to oil shale and shale products and cancer incidence (29). This study is to follow up on limited dermatological investigations by U.S. Public Health Service of some 800 shale workers who were employed at Anvil Points in the early 1950s. The NIOSH study is aimed at determining possible latent effects of occupational exposure.

Suspected Carcinogens in Shale Products

A variety of known and suspected carcinogens belonging to the POM* class have been identified in crude shale oil and shale oil products. Some reported levels of Benzo(a) Pyrene (BaP) in shale derived materials are listed in Table 3-15. Other carcinogenic compounds in the POM class have also been tentatively identified in shale products, including 3-methylcholanthrene and an isomeric mixture of dimethylbenz(a)-anthracenes (12,24). Generally, POM's have high boiling points (about 300°C) and are found in the higher boiling distillates or residues of shale oils, including shale oil coke and carbonaceous residues associated with processed shale (13).

Some of the controversy about the carcinogenicity of shale derived materials arises from the use of BaP content as an indicator of activity. Levels of BaP in shale oils are generally in the same range as levels found in similar boiling range petroleum oils, suggesting that shale oil presents no more of a hazard than petroleum (11,12,14,15). However, experimental tests with crude shale oil and various distillate fractions have shown that the carcinogenic potency by non-human bioassay techniques cannot be attributed to the presence of benzo(a)pyrene alone (13,16,17,18,19,20,21). Other carcinogenic or co-carcinogenic compounds may be present. Conversely, high measured levels of BaP in a material do not necessarily indicate biological availability. TOSCO II retorted shale for example, has not been shown to be a skin carcinogen in sensitive mice exposed to it as bedding, while benzene extracts of such shale are carcinogenic to the skins of mice (12). Other pathological tests on the internal organs of these mice are still in progress. It should be noted that BaP has not been demonstrated to be a carcinogen in man (25).

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*Polycyclic Organic Matter

Bioassay Tests

A major problem for establishing the degree of cancer hazard for humans presented by materials such as shale oil is that tests cannot be directly performed on humans. Animal testing results, in addition to being expensive to obtain, cannot readily be extrapolated to humans. Epidemiological studies are also expensive, may take years to produce results, and suffer from lack of control of other factors which may affect cancer incidences. One simple but promising test for screening potentially carcinogenic substances and materials is the Ames (or Salmonella Reversion) Test (26). The Ames test is based on the empirical observation that many mutanogenic substances are also carcinogens, and that certain strains of bacteria are good test organisms for indicating the mutanogenic properties of substances (27). Several federal agencies and private organizations are currently screening synthetic fuel related materials for potential carcinogenic properties using the Ames and related tests (28).

Experiments with test animals (mice and rats) have shown that only certain fractions of crude and refined shale oils exhibit carcinogenic activity. High boiling distillation fractions of shale oil have been shown to be carcinogenic to the skins of mice (9,10,20), and the active fractions do not necessarily contain large amounts of BaP (21). The Colony Development has contracted with the Eppley Institute for animal testing of shale derived materials (12). Based on the results of the Eppley studies, carcinogenic potency indices for various hydrocarbon material have been determined. Table 5-3 shows a comparison of the relative potency of some petroleum and shale derived materials. The indices suggest that shale derived oils are similar to petroleum oils of comparable boiling range or intended use, and that upgraded (hydrotreated) shale oil is significantly less potent than crude shale oil. It might be commented that a latency period is required for the development of carcinogens in mice, and toxic substances other than POM in shale oil can cause death before cancers might normally occur (20).

Potentially Carcinogenic Materials in Waste Streams Associated with Shale and Shale Oil Processing

The presence of suspect carcinogens in shale products suggests that waste streams associated with processing may also contain such substances. Some of the studies regarding retorted shale have been reviewed in Section 3.3.2. Air and waterborne emissions and effluents resulting from retorting, upgrading, and refining operations may also contain such substances (Sections 3.1.1 and 4.2). Generally, little is known about the hazards of shale related waste streams, since retorting and refining operations conducted to date have been limited in scope and size, and have been aimed primarily at demonstrating technology rather than determining effluent quantities and properties.

Based on analytical data, animal testing, and epidemiological studies, some generalizations can be made about the carcinogenic hazard of shale derived materials:

- High boiling shale derived oils and carbonaceous residues contain BaP and other POM.

- Levels of BaP in shale derived products are similar to levels found in analogous petroleum derived oils and residues.
- BaP content may not necessarily be a good indicator of carcinogenic activity in test animals, both because of the possible presence of other carcinogens and because analytical measurements do not necessarily indicate bioavailability.
- Industrial exposure of humans to certain shale products has been correlated to cancer incidences, but the correlation is no stronger than that between exposure to many petroleum and coal derived substances and cancer.
- Good industrial hygiene practices and isolation of workers from exposure can dramatically influence occupational cancer incidences.
- Bacterial and animal test results regarding the carcinogenicity of substances or materials cannot directly be related to carcinogenicity in man.
- Little is known about actual hazards to workers or the general population from carcinogens which might be present in the waste streams of shale and shale oil processing operations.

Table 5-3. Comparable Carcinogenic Potency of Complex Mixtures (12)

Oil Product	Potency Index Based on Mouse Skin Tests
Industrial Fuel Oil	0.17
Naphthenic Distillate	0.06
Dewaxed Paraffin Distillate from Petroleum	0.06
Cracked Sidestream	0.26
Coke Oven Coal Tar	0.54
Crude Shale Oil	0.10
Upgraded Shale Oil	0.03
3-methylcholanthrene (reference compound)	1.0

5.3 EMISSIONS FROM THE COMBUSTION OF SHALE OIL PRODUCTS

Emissions from the combustion of fossil fuels may be divided into two broad categories; those which occur due to the inherent properties and composition of the fuel, and those which occur as a function of combustion parameters. Sulfur dioxide belongs in the first category, while carbon monoxide and hydrocarbons belong to the second category. Particulate emissions can be placed in both categories; sooty material accompanying incomplete combustion, and ash derived from inorganic and noncombustible components of the fuel. Similarly, oxides of nitrogen occur in combustion gases both from oxidation of fuel nitrogen and from the non-equilibrium reaction of atmospheric nitrogen and oxygen at combustion temperatures.

The properties of crude shale oil have been discussed previously(Sec. 5-1) The high nitrogen content and, to a lesser extent, the inorganic content of the refined shale oils are the properties which present the major emissions potential.

Very little information is available about emissions from the combustion of crude shale oils. Limited emissions information has been made available recently from the testing of refined fuels from the Paraho project. The data at present indicate that shale derived fuels are not significantly different from their petroleum derived counterparts in either performance or emissions characteristics. In the case of the products from the 1975 Paraho refining run, slightly higher nitrogen and ash contents of certain fractions account for differences in emissions between shale and petroleum derived fuels (6,7). About 50% of fuel nitrogen is converted to NO_x during combustion. The Southern California Edison Company tested Paraho shale oil in July of 1976 at the Highgrove, California generating station, but emissions data has not been released.

Particulate polycyclic organic matter may be emitted during the combustion of shale oil and its higher boiling distillate fractions. However, emissions of POM are a function of combustion parameters as well as shale oil composition. Further, evidence to date suggests that particulate POM emissions associated with combustion of refined shale oils are not inherently greater than those from combustion of similar boiling range petroleum oils.

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6.0 ENVIRONMENTAL MONITORING PROGRAMS AND STUDIES

This chapter is a summary of monitoring projects and studies which have been or are being conducted in the Piceance and Uinta Basins, and which are relevant to oil shale development. Two general classes of programs are considered: (1) private and/or specialized projects and (2) projects connected with the Federal Prototype Oil Shale Leasing Program. Section 6.1 is a catalog and brief description of various activities, most of which have been conducted independently of each other. Section 6.2 is a narrative summary of and commentary on the monitoring programs of the lease tracts. Section 6.3 provides some comments about monitoring programs with focus on scope, quality, and the availability of data and results to interested parties.

6.1 MONITORING AND ENVIRONMENTAL STUDIES BY PRIVATE INDUSTRY, UNIVERSITIES, AND CERTAIN GOVERNMENT AGENCIES

The major companies with interest in oil shale and several other organizations have been involved in various aspects of baseline environmental monitoring. Some of the data and results of the private programs are publically available and have been published in research papers, conference proceedings, Environmental Impact Assessments or statements, and other documents. For example, the Colony Development Operation has conducted and published the results of numerous monitoring, modeling, and mitigation studies (1,2). Many additional studies have been discussed and referenced in the preceding chapters of this report.

Other data or findings are not generally available to the public at present. However, EIA or EIS reports are expected from Union and Occidental in the next year or so if the climate for commercial development improves.

Tables 6-1 through 6-4 summarize the projects dealing with meteorology and air quality, surface and ground water, solid wastes, and revegetation. The tables are largely self explanatory. Although the attempt was made to cover all projects which have been conducted or are known to exist at present, no doubt some activities are not listed. The major information sources for Tables 6-1 to 6-4 are References 3,4,5, and 6.

6.2 ENVIRONMENTAL PROGRAMS OF THE FEDERAL PROTOTYPE OIL SHALE LEASING PROGRAM

After the final EIS prepared by the Department of the Interior was approved in 1973, six 5,120-acre tracts (two each in Colorado, Utah, and Wyoming) were offered for lease in 1974. (See Section 2.4) No bids were received for the Wyoming tracts and, as envisioned in the EIS, the two contiguous Utah tracts opted to operate jointly so that the three operations at present are

Table C-1. Summary of Meteorology and Air Quality Monitoring and Studies

Project	Ambient Quality Monitoring	Meteorological Data - Ground Level	Inversion & Diffusion Studies	Health Hazard Studies & Control Technology
Colony Development Operation	SO_2, THC, NO_x, Particulates monitored at Parachute Creek plant site, other valley & plateau locations. Trace elements in particulate matter also measured. Started 1971.	Wind speed, direction, temp. relative humidity, precipitation at 8 stations in Parachute Creek Valley & Plateau. Started 1971.	Balloon & tracer studies, started in 1972. Diffusion modeling.	● Mine dust studies - respirable concentrations, size characteristics, TLV estimates. ● Dust & diesel emission control techniques. ● Spent shale dust carcinogenic studies.
Union Oil Company	Two stations started 1974 - particulates. One station - SO_2, NO_x, CO, THC.	Wind speed, direction, temp. relative humidity at 9 stations, 30' & 200' levels. Precipitation, evaporation at 5 stations. Started July 1975.	Upper air studies July, Oct. 1974 & Jan, April 1975.	Not known
Occidental	Hi-Volume Particulate samplers located at expected max stack plume concentration site and at plant site. Recently added gaseous pollutant monitors.	2 met. stations, on & near plant site - wind speed, direction precipitation. Started 1972.	Upper air and inversion studies.	Particulate sampler at mine collects samples for carcinogenic testing.
Superior	Plant site monitoring of ambient air quality planned for 1977.	Wind speed, direction temperature, humidity at 4 sites; precipitation at one site.	Upper air studies planned for 1977.	

Table 6-2. Summary of Surface and Ground Water Monitoring Activities

Project	Stream Flow	Surface Water Quality	Ground Water Pumping Tests & Water Quality	Precipitation/ Runoff Studies	& Other Studies
Colorado State	Spring flow being monitored at 73 locations in Piceance Creek Basin	Spring water quality being analyzed for 73 locations in Piceance Creek Basin.			
US Geological Survey	Streamflow being monitored at more than 50 locations on Colorado River and major tributaries. All thru Piceance Cr. Basin, USGS monitors 21 additional stations for flow with the support of industry. USGS to monitor for spring flow along Parachute & Roan Creeks.	Water quality and sediment analyzed for all stations operated by USGS. USGS to monitor spring water quality along Parachute and Roan Creeks.	Groundwater data collected on 97 wells by USGS as part of CDSEP study (includes data on test lease tracts). USGS has drilled 22 holes at 11 locations for testing in 1976 -- water occasionally monitored at domestic wells and open holes along stream.		USGS modeling studies reported in Prof. Paper 908 and various open file reports. Describe simulated effects of development on hydrology of Piceance Creek basin.
US Weather Bureau				Maintain weather stations at towns in the area -- plus Little Hills station in the Piceance Cr. basin	
Federal Energy Adm (Contracted to Colo. St. Univ. but not completed)					DOI electronic computer simulation model to determine water availability in the White River Basin.

Table 6-2. Summary of Surface and Ground Water Monitoring Activities (Contd)

Project	Stream Flow	Surface Water Quality	Ground Water Pumping Tests & Water Quality	Precipitation/ Runoff Studies	Modeling & Other Studies
Colony	13 gauging stations on Parachute Creek	11 stations in Parachute Creek Basin.	Not known	Runoff & salt load study for upper Parachute Creek	
Union	6 gauging stations on Parachute Creek	Periodic sampling since 1958. 6 weekly stations started in 1974.	Pumping and water quality testing at 5 wells, started Jan. 1975.	Precipitation at 5 stations in Parachute Creek	
Occidental	Intermittent drainages at trash dumping site monitoring, started 1975.	Water quality samples for springs & intermittent flows of streams.	Mine water quality samples taken.	Not known	
Superior	USGS gauging station on Piceance Creek, on Superior property.	● Sediment @ one site, Piceance Creek. ● 4 chemical quality stations on Parachute Creek. ● 2 chemical quality stations on the White River. ● Chemical quality on Alkali Springs.	● Fluid level recording on 7 coreholes. Pump testing of 2 coreholes in leach zone by USGS, plus transmissivity. ● Water quality in two abandoned cable tool wells.		
Cameo II Studies (comprised 17 Organizations; others may join at $80,000/ participant)					An electronic computer simulation model of the White & Colorado River Basins to simulate operating conditions and input parameters to be determined by the user.

Table 6-1. Summary of Spent Shale/Solid Waste Disposal Projects

Project	Physical Stabilization/ Properties of Spent Shale	Leaching Studies
Colony	Has conducted or supported several studies: ● Moisture requirements, handling, compacting spent TOSCO II shale. ● Mine backfilling. ● Liquefaction studies of disposal piles. ● Slope stability studies.	● Water balance in Davis Gulch disposal area - irrigation & leaching requirements. ● Leaching studies in connection with revegetation work. ● Colony is supporting stability & leaching of spent shale containing representative quantities of other wastes (coke, catalysts, etc.)
Union	Physical properties and compaction studies in connection with revegetation research both at Parachute Creek and at Brea, Calif.	
Paraho, Anvil Points	Joint Paraho/USBM/EPA project for defining retorted shale handling and disposal systems. Specifically aimed at Paraho spent shale rather than TOSCO type spent shale. Major emphasis on water requirements, compaction, permeability and cementation.	Leaching studies are part of revegetation research at Anvil Points by Colorado State University, and the Paraho/USBM program for processed shale management.

Table 6-4. Summary of Revegetation Projects

Project	Nature of Revegetation Work
Colony	1966-1974: Greenhouse, valley, and plateau tests with TOSCO II spent shale. Studies on plant assimilation of trace metals and organics from spent shale at Rocky Flats Research Center. Colony sponsored several CSU studies of plant growth in TOSCO II spent shale.
Union	Revegetation of Union A spent shale at Parachute Creek site, 1965-1967. Greenhouse revegetation and leaching studies 1967-1974, at Brea, Calif. Valley and plateau plots established in 1974 in Parachute Creek area. Recent work has emphasized Union B spent shale, since that is what will be produced during commercial production.
Paraho (Anvil Points)	Revegetation test plots on processed Paraho shale were established in 1975 at Anvil Points. The revegetation was highly successful due mainly to the large amounts of water applied. Under contract to EPA, Colorado State University has undertaken at Anvil Points in 1976, a new, more ambitious program to compare revegetation of processed Paraho shale covered with various depths of topsoil.
TOSCO/Forest Service/EPA Project	The Department of Agriculture established a Surface Environment and Mining (SEAM) program some years ago for joint funding by government/industry of rehabilitation projects on disturbed lands. TOSCO has entered into such an agreement with the Forest Service for a project involving upper and lower plots in the Parachute Creek/Roan Cliffs area to experiment on revegetation of processed TOSCO II shale in realistic situations. TOSCO further intends to perform ecosystem studies in conjunction with these plots.
Rio Blanco "Shot" Test Plots.	In 1974, at the site of the Rio Blanco nuclear stimulation test, plots were laid out on processed shale. Irrigation was done at irregular intervals and the plots failed. They were reconstructed in 1975.
Soil Conservation Service Plant Materials Center.	The SCS, with support from the Fish & Wildlife Service, EPA, and several other sources, has established a plant materials center in Meeker, Colo. for the Western Oil Shale Region. Such a center will help develop & multiply plant materials for various purposes including processed shale revegetation. Due to the salutary climate and resultant ecosystems in the Meeker area, this center will be of limited use for revegetation in the Piceance & Uinta basins.

Table 6-4. Summary of Revegetation Projects (Contd)

Project	Nature of Revegetation Work
Wolf Ridge Plots.	Colorado State University has proposed a long range revegetation program to ERDA (not yet funded) for work on Wolf Ridge, a few miles east of Tract C-a. This proposal is unique in that it would be a long range ecosystem study rather than a narrow revegetation project. One obvious difficulty is the limited supply of either TOSCO II or Paraho processed shale for use.
84 Mesa Test Plots	Test plots were laid out on a flat area a few miles northeast of Tract C-a in 1973 and again in 1974 to test the revegetation potential of numerous native & exotic grasses, forbs, and shrubs. No irrigation was used. Some species show promise.
Colorado State University/Colo. Dept. of Natural Resources/U.S. EPA	Test plots at two elevations (5700 ft and 7300 ft) using TOSCO II and USBM retorted shales. Several soil thickness layers have been investigated. Salinity measurements taken in piles, leachate, and runoff. The published results in 1974 indicated that resalinization following leaching of shale can limit the success of vegetative establishment, although some cover has been partially established at both sites. Plots are being monitored to determine longer term success.

C-a (Rio Blanco Oil Shale Project), C-b (Roxana Oil Shale Project), and U-a/U-b (White River Shale Oil Project).

The lease documents (7,8,9) contain extensive environmental stipulations. The baseline survey, as defined by the lease stipulations, is a two year study (one year must be completed before submission of the Detailed Development Plan) which must be completed before commercial operations may begin. The baseline is to define the environment as it exists now; however, lack of a philosophical foundation for the baseline science has necessitated pragmatic decisions by federal/state agencies and industries. This has led to differing expectations about what the baseline survey will and will not accomplish. The baseline survey, as it is now being conducted, is the product of specific lease stipulations plus many months of joint negotiations between all interested parties (federal/state/industry). In the process, the Area Oil Shale Supervisor has defined and/or added to the stipulations.

Because of the lessees' concerns of anti-trust action if baseline studies were performed jointly, and because of varying ecological conditions on the tract, the three lessees have mounted distinctly different and separate environmental monitoring efforts. For a first-effort baseline program, multiple approaches have the advantage of investigating methods for future operations. But the disadvantage is the potential difficulty of directly comparing certain results between the tracts. At this stage of environmental baseline science, the advantages probably outweigh the disadvantages. It would be useful to perform a critical review at the completion of the ongoing environmental programs, to determine the most appropriate baseline survey data and methods, and to standardize the rationale for future efforts.

6.2.1 Geotechnical Data Gathering

This part of the baseline survey is not of major environmental interest, but some parts of this effort have important relationships to the environmental survey.

Geology: Each lessee has conducted the classical core-hole drilling and logging program to define reserves on the tract. Fischer assays for shale richness, sodium and aluminum analyses for recoverable Nahcolite and Dawsonite, and analyses for seven trace elements (As, B, Cd, F, Hg, Sb, Se) have been made on core samples to investigate resource and environmental potentials. Interpretation of some of these data has been inconclusive to date. For example, there is general lack of knowledge of the mobility, bioavailability, and hazards associated with trace elements.

Hydrology: The presence and location of aquifers has been determined by all the lessees. Because mine dewatering is necessary for both underground and open-pit mining, the lessees have modeled subsurface aquifers for eventual dewatering operations. Baseline water quality has been extensively measured (both ordinary chemical parameters as well as trace elements) even though the lessees propose a "no discharge" practice for effluent waters from commercial operations.

6.2.2 Environmental Baseline Programs (6,10,11,12)

This program can be divided into two sections: those projects that are continuous over a two-year interval and those that essentially are "one-shot" programs that may or may not need to be completed within the two-year time frame.

Air Quality and Meteorology (AQ & MET): Each tract, by lease stipulation, is to have four AQ-MET stations or or about its property (eight for the joint U-a/U-b). Both C-a and C-b have two stations fully instrumented for AQ parameters (SO_2, H_2S, NO, NO_x, O_3, CH_4, CO, nonmethane hydrocarbons, particulates) and two partially instrumented. U-a/U-b has three stations fully instrumented. The initial requirement, now changed, was 90% recovery of AQ data. It should be noted that approximately 5-9% of total time is needed for calibration and zeroing of certain instruments. Difficulties are encountered in operating such remote stations, and the 90% recovery requirement may be hard to meet.

MET stations are coincidental with AQ stations. The "main" station has either a 30 to 60 meter tower taking data at three levels. Wind speed and direction, temperature, humidity, rainfall, and solar isolation, delta T and wind sigma are obtained for use in modeling. The ancillary stations have 10 meter towers measuring the normal MET parameters (eg, wind speed and direction). The lease requirement for 95% data recovery has not been too difficult to meet to date. Isolated cases have occurred, such as a solar insolation meter being "knocked out" by lightning flashes.

Upper Air Studies and Diffusion Modeling: Although not a part of the original lease stipulations, lessees have been required to perform four quarters of upper air studies, 15 actual days each quarter. (Tracts C-a and C-b have conducted a fifth quarterly study.) These studies are necessary for diffusion modeling and demonstration of compliance with federal/state air quality standards.

Tract C-a had planned tracer studies to validate the diffusion model, but these plans were initially aborted due to dust problems. However, RBOSP has recently completed field work in connection with tracer studies. These studies will be essential to ultimate plant design and should have been made part of the lease stipulations.

Tracts C-b and U-a/U-b have acoustical sounders to measure inversion layers. The upper air studies have also provided inversion data albeit on a less continuous basis.

Terrestrial Biology: The greatest variations and difficulties in the baseline programs are to be found in the biological studies. Despite the concerted efforts of the International Biological Programs, no standard method of evaluating biological ecosystems is entirely agreed upon. Both techniques of measurement and methods of modeling ecological interrelationships remain an enigma. All three tracts are performing more or less complete analyses of the flora and the small mammal fauna. These components essentially determine the local ecosystem dynamics. But the "politics" of big game animals and birds have influenced the focus and efforts of the programs. Further, considerable effort is being placed on investigations of amphibians and reptiles, while far less is being placed on the invertebrate populations, especially on the effects of grazing pressure in these ecosystems.

The leases stipulate bimonthly sampling periods. Sampling periods patterned after animal activity patterns instead of arbitrary calendar periods, could perhaps be more useful.

Game Management Plan: The lease stipulations requires lessees to formulate game management plans on and about the tracts. Since game management is a responsibility of federal/state agencies, it is not certain how such plans can interrelate with government programs without usurping their powers and authority. To date, the game management plans consist mostly of species lists and a cooperative attitude between industry/government.

Aquatic Biology: The aquatic biological component of the baseline survey is actually geared to more humid regions. Major streams and rivers are well monitored with slightly less emphasis on seeps, springs, and intermittent creeks. Phytoplankton, zooplankton, periphyton, benthos, macrophytes, and fish are being measured. If these data can be related to terrestrial ecosystems, they will be of compelling interest.

Water quality (W.Q.) data is being intensively collected at each aquatic biology station. These data are of the utmost importance and will be absolutely necessary for future comparisons after commercialization. All normal parameters plus trace elements are being measured. Other W.Q. data is being collected in cooperation with the U.S.G.S. programs (Table 6-2).

Soil Mapping and Analysis: Adequate soils maps and knowledge of the interrelationships of soil and flora are essential not only to an understanding of local ecosystem dynamics but also to proper long-term revegetation planning. All three lessees have completed soils data gathering projects.

Revegetation: Lease stipulations require an acceptable and demonstrated plan in the Detailed Development Plan or firm plans to obtain such acceptable revegetation before commercialization. Each of the lessees because of differing mining procedures and local ecosystems, has proposed different revegetation plans and has undertaken its own unique testing program to prove the benefits of these plans. C-a lessees, proposing open-pit mining, plan to cover processed shale with overburden sized to prevent upward capillary movement of salts. C-b proposes to revegetate on about six inches of topsoil placed directly over processed shale. U-a/U-b plans to terrace processed shale, coat the surface with a temporary impermeable plastic, form trenches of soil in the low spots, and use these as water catchment systems. Water is not nearly as great a problem in Colorado's Piceance Creek Basin as in Utah's Uinta Basin. All lessees are undertaking trials of these systems with U-a/U-b performing the most extensive work.

Toxicology: Processed shale contains small amounts of potentially hazardous organic compounds. The potential carcinogenicity problem is only part of the overall toxicology problem associated with any new material and process. The lessees of Tract C-b, through their connection with the Colony Development operation, have contracted for extensive carcinogenic animal testing programs, from which results are now beginning to appear. The lessees of tract C-a have openly spoken of plans to perform an extensive overall toxicology program not only on spent shale but on shale oil and its products, but the program has not begun to date.

Trace Element Analyses in the Ecosystem: One of the unresolved questions in revegetation plans is whether processed shale piles will introduce dangerous levels of trace elements into the environment either through erosion or through uptake into plants. A baseline is needed for levels of these elements in the local ecosystems (see Section 6.2.1). All three lessees are conducting somewhat different programs to measure present levels in soils, flora, and fauna.

Archaeology, Paleontology, and Historical Values: Federal laws require archaeological, paleontological, and historical clearance of areas before disturbance. All lessees have mounted and finished extensive, professional clearance projects on and about the leases.

Visibility and Scenic Studies: Lessees have undertaken visibility studies by photographic techniques, which should be most useful as a check on air quality degradation from future pollution. However, other scenic values are rather subjective, and descriptive techniques are the only available measuring technique.

Ecological Interrelationships: The leases stipulate that ecological interrelationships be addressed, which is a requirement of the National Environmental Policy Act (NEPA). However, in the strictly scientific sense, it is not yet known how to adequately treat this requirement. It has been addressed in many ways in the Detailed Development Plans (eg. by descriptive words and by charts), but adequate models have not been developed.

6.2.3 Continuous Monitoring Programs

After the baseline studies are completed and when commercialization begins, a continuous monitoring program is to be undertaken to compare the ecosystems "before and after" and to serve as a warning system for possible degradation of the environment. As stated in the Detailed Development Plans, the lessees plan to continue the baseline studies at a less intensive but sufficient level to measure changes that may occur. There is little need for a separate and distinct transition period unless a long delay ensues between the end of the two-year baseline study and the beginning of commercial operations. In such an event, the lease stipulates that monitoring begin six months before commercialization. Monitoring will continue for the life of the project and for that amount of time afterward necessary to ensure compliance with lease stipulations. Source monitoring will also be necessary once construction and commercial operations begin on the tracts.

6.3 COMMENTS ON MONITORING PROGRAMS

The projects listed and summarized in this chapter differ dramatically in scope, purpose, and approach since the goals of individual sponsors vary.

For most of the potential environmental impacts associated with oil shale development, a corresponding project or series of projects aimed at baseline or impact monitoring, or at mitigation, exists. The use of data and project results to assess environmental impacts on both a site-specific and regional basis is difficult for three primary reasons. First, information is fragmented and in many cases, not publically available. Secondly, the types of data gathered have been dramatically different for different projects. Thirdly, the reporting and formating of data and information has not been uniform. A few comments regarding the adequacy of data and programs dealing with air, water, solid wastes, and revegetation are presented below.

6.3.1 Air Quality and Meteorological Monitoring

Adequate baseline air quality and surface meteorological data have been or are being collected at most development sites. As development proceeds, source monitoring should be initiated. Upper air studies have been conducted at most sites, and the results are sufficient to indicate maximum impact sites for placing ambient source monitors. Additional upper air studies may be needed for model input purposes (to define local inversion, turbulance, etc.).

6.3.2 Surface and Ground Water Monitoring

If present surface water gaging stations are maintained, it appears that adequate background data will be available for determining the effects of direct discharges of most oil shale development activities on surface water. A possible exception is Occidental; adequate information is not available for appraising their baseline monitoring program at present.

Considerable subsurface hydrologic testing has been conducted in the Piceance Creek and Uinta basins. In the southern Piceance Creek and eastern Uinta basin, the hydrology is reasonably well known, and adequate monitoring programs have been or can be developed for determining the effects of oil shale activities on subsurface waters. However, in the northern part of the Piceance Creek basin interpretations differ substantially as to the effects that oil shale development may have on the hydrologic regime. The crux of the problem is the extent to which rich oil shale units within each of the two major aquifers impede vertical flow. Until sufficient data are available to define vertical flows, adequate prediction of the effects of activities such as mine dewatering on the surface water flows and quality cannot be made. None of the current water monitoring programs are designed to obtain the information required for better characterization of the aquifer systems. One approach might be to establish a program of pump testing of individual wells at distinct depth intervals, and monitoring water levels in two or more nearby wells.

6.3.3 Solid Wastes

Several projects have addressed retorted shale handling and disposal. Activities supported by Colony and Union in particular, have contributed greatly to design and operational planning for retorted shale disposal. A recent Colony project, for example, is aimed at determining physical properties and leaching potential of processed shale containing representative amounts of other solid wastes (spent catalyst, coke, lime sludges, etc.).

All research and monitoring programs to date have dealt with relatively small quantities of retorted shale. Potential problems such as mass stabilization of shale piles, or the maintainence of an impervious layer below plant root zones, can likely be defined and solutions found only by creation of a large pile. Commercial scale oil shale processing will be necessary in order to allow the necessary experiments to be performed.

6.3.4 Revegetation

Numerous experiments and studies have been directed toward demonstrating vegetative stabilization of the surface of retorted shale piles. The applicability of the findings of such studies to large scale revegetation of retorted shale may not be straightforward. Plot experiments have been conducted mainly at valley sites in Piceance Basin, and the results may have no relevance to plateau sites in Uinta basin. Irrigation, mulch, and fertilizer applications found to be successful in experimental plots may not be practical for large plots. Plant succession and the establishment of deep rooted shrubs and trees have not been (and perhaps may not easily be) adequately researched. One inherent problem for more extensive revegetation research and monitoring is the current shortage of retorted shale.

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